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 September 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 October 21, 2005, (i) the number of shares of Puget Energy, Inc. common stock outstanding was 100,467,398 ($.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;
- air quality regulatory requirements at the federal, state and local government levels may impact PSE's generation and costs as climate change has made emissions management complex due to efforts being made to further reduce emissions from all utilities. Proposed legislation and new regulation remain unsettled or unresolved, including climate change legislation, the Clear Skies Initiative and the recently promulgated Clean Air Mercury and Interstate Rules. As a result, uncertainty with respect to renewable energy mandates, potential Green House Gas regulation and new limits on emissions could impact PSE and others;
- 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 impede PSE's ability to manage its energy portfolio risks and procure energy supply, affect the availability and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers and;
- the effect of wholesale market structures (including, but not limited to, regional market designs or transmission organizations such as Grid West or the Transmission Improvement Group, 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;
- natural disasters, such as hurricanes, which can cause temporary supply disruptions, and/or price spikes in the cost of fuel and raw materials;
- 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 maintain current key customer relationships, 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 SEPTEMBER 30, 2005	THREE MONTHS ENDED SEPTEMBER 30, 2004	NINE MONTHS ENDED SEPTEMBER 30, 2005	NINE MONTHS ENDED SEPTEMBER 30, 2004
Operating revenues:				
Electric	$ 375,035	$ 322,669	$ 1,140,545	$ 1,018,256
Gas	111,042	89,433	594,737	484,603
Other	4,306	2,925	6,866	4,005
Total operating revenues	490,383	415,027	1,742,148	1,506,864
Operating expenses:				
Energy costs:				
Purchased electricity	200,861	147,589	587,983	517,803
Electric generation fuel	21,058	25,130	54,400	60,132
Residential exchange	(34,525)	(34,014)	(126,676)	(123,799)
Purchased gas	59,151	44,574	359,037	270,683
Unrealized net (gain) loss on derivative instruments	477	1,894	395	(1,042)
Utility operations and maintenance	81,645	67,093	240,299	214,149
Other operations and maintenance	745	529	2,045	1,513
Depreciation and amortization	60,550	57,598	178,284	170,036
Conservation amortization	5,633	4,747	16,746	17,746
Taxes other than income taxes	44,784	42,711	165,005	149,486
Income taxes	2,476	6,958	54,649	40,621
Total operating expenses	442,855	364,809	1,532,167	1,317,328
Operating income	47,528	50,218	209,981	189,536
Other income (deductions):				
Other income	1,422	356	4,184	1,994
Interest charges:				
AFUDC	2,680	1,650	6,183	3,807
Interest expense	(45,695)	(42,754)	(130,307)	(128,796)
Mandatorily redeemable securities interest expense	(23)	(23)	(68)	(68)
Income from continuing operations	5,912	9,447	89,973	66,473
Income (loss) from discontinued operations, net of tax	(1)	1,677	908	4,237
Net income	$ 5,911	$ 11,124	$ 90,881	$ 70,710
Common shares outstanding weighted average (in thousands)	100,371	99,580	100,160	99,373
Diluted common shares outstanding weighted average (in thousands)	100,964	100,043	100,754	99,836
Basic earnings per common share from continuing operations	$ .06	$ .09	$ .90	$ .67
Basic earnings per common share from discontinued operations	--	.02	.01	.04
Basic earnings per common share	$ .06	$ .11	$ .91	$ .71
Diluted earnings per common share from continuing operations	$ .06	$ .09	$ .89	$ .67
Diluted earnings per common share from discontinued operations	--	.02	.01	.04
Diluted earnings per common share	$ .06	$ .11	$ .90	$ .71

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 SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2005	2004	2005	2004
Net income	$ 5,911	$ 11,124	$ 90,881	$ 70,710
Other comprehensive income, net of tax at 35%:				
Foreign currency translation adjustment	2	(5)	(10)	235
Unrealized gains on derivative instruments during the period	37,896	17	48,484	11,577
Reversal of unrealized gains on derivative instruments settled during the period	(4,353)	(2,829)	(3,243)	(6,910)
Loss from settlement of cash flow hedge contracts	--	--	(22,960)	--
Amortization of cash flow hedge contracts to earnings	191	--	264	--
Deferral of cash flow hedges related to the power cost adjustment mechanism	(12,914)	(5,501)	(4,937)	(8,187)
Other comprehensive income (loss)	20,822	(8,318)	17,598	(3,285)
Comprehensive income	$ 26,733	$ 2,806	$ 108,479	$ 67,425

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

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

ASSETS

	SEPTEMBER 30, 2005	DECEMBER 31, 2004
Utility plant: (at original cost, including construction work in progress of $311,783 and $129,966, respectively)		
Electric	$ 4,645,289	$ 4,389,882
Gas	1,966,806	1,881,768
Common	436,822	409,677
Less: Accumulated depreciation and amortization	(2,566,492)	(2,452,969)
Net utility plant	4,482,425	4,228,358
Other property and investments	157,249	157,670
Current assets:		
Cash	9,817	12,955
Restricted cash	1,045	1,633
Accounts receivable, net of allowance for doubtful accounts	112,283	137,659
Unbilled revenue	81,265	140,391
Purchased gas adjustment receivable	37,508	19,088
Materials and supplies, at average cost	33,931	31,683
Fuel and gas inventory, at average cost	95,096	65,895
Unrealized gain on derivative instruments	203,419	14,791
Prepayments and other	34,485	6,858
Deferred income taxes	--	1,415
Current assets of discontinued operations	122,664	110,922
Total current assets	731,513	543,290
Other long-term assets:		
Regulatory asset for deferred income taxes	135,194	127,252
Regulatory asset for PURPA contract buyout costs	196,188	211,241
Unrealized gain on derivative instruments	38,956	21,315
Power cost adjustment mechanism	5,583	--
Other	383,662	401,795
Long-term assets of discontinued operations	161,753	160,298
Total other long-term assets	921,336	921,901
Total assets	$ 6,292,523	$ 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

	SEPTEMBER 30, 2005	DECEMBER 31, 2004
Capitalization:		
Common shareholders' investment:		
Common stock $0.01 par value, 250,000,000 shares authorized, 100,459,935 and 99,868,368 shares outstanding, respectively	$ 1,005	$ 999
Additional paid-in capital	1,634,600	1,621,756
Earnings reinvested in the business	29,679	13,853
Accumulated other comprehensive income (loss), net of tax at 35%	3,266	(14,332)
Total shareholders' equity	1,668,550	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	2,068,360	2,069,360
Total redeemable securities and long-term debt	2,307,999	2,351,499
Total capitalization	3,976,549	3,973,775
Minority interest in discontinued operations	6,151	4,648
Current liabilities:		
Accounts payable	216,668	226,478
Short-term debt	223,871	--
Current maturities of long-term debt	46,000	31,000
Accrued expenses:		
Taxes	77,297	81,315
Salaries and wages	12,125	13,829
Interest	42,901	29,005
Unrealized loss on derivative instruments	14,643	26,581
Deferred income taxes	19,593	--
Tenaska disallowance reserve	--	3,156
Other	28,994	34,918
Current liabilities of discontinued operations	73,783	51,892
Total current liabilities	755,875	498,174
Long-term liabilities:		
Deferred income taxes	760,382	795,291
Unrealized loss on derivative instruments	--	385
Other deferred credits	620,525	395,236
Long-term liabilities of discontinued operations	173,041	183,710
Total long-term liabilities	1,553,948	1,374,622
Total capitalization and liabilities	$ 6,292,523	$ 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)

	NINE MONTHS ENDED SEPTEMBER 30,	
	2005	2004
Operating activities:		
Net income	$ 90,881	$ 70,710
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	178,284	183,614
Deferred income taxes and tax credits, net	(32,329)	65,294
Net unrealized (gain) loss on derivative instruments	395	(1,042)
Cash collateral received from energy suppliers	31,050	8,520
Increase in residential exchange program	4,984	8,452
Impairment on InfrastruX investment	13,204	--
Other	18,733	20,588
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	70,084	80,563
Materials and supplies	(2,781)	(5,281)
Fuel and gas inventory	(29,201)	(26,671)
Prepayments and other	(28,301)	(11,159)
Purchased gas adjustment receivable	(18,419)	(30,157)
Accounts payable	(9,269)	(49,305)
Taxes payable	7,339	(50,884)
Tenaska disallowance reserve	(3,156)	11,212
Accrued expenses and other	9,503	7,619
Net cash provided by operating activities	301,001	282,073
Investing activities:		
Construction and capital expenditures - excluding equity AFUDC	(406,346)	(324,292)
Energy efficiency expenditures	(10,763)	(13,301)
Cash proceeds from property sales	15,830	672
Refundable cash received for customer construction projects	10,221	9,497
Restricted cash	587	(1,240)
Other	2,348	521
Net cash used by investing activities	(388,123)	(328,143)
Financing activities:		
Change in short-term debt, net	230,855	10,618
Dividends paid	(65,956)	(65,050)
Issuance of common stock	3,769	3,914
Issuance of bonds	250,000	336,000
Redemption of bonds and notes	(250,753)	(243,982)
Redemption of trust preferred stock	(42,500)	--
Settlement of cash flow hedge derivative on treasury rate lock	(34,776)	--
Issuance and redemption costs of bonds and other	(8,356)	(1,700)
Net cash provided by financing activities	82,283	39,800
Net decrease in cash	(3,137)	(79)
Change in cash from discontinued operations	(1,702)	(6,191)
Cash at beginning of year	19,771	27,481
Cash at end of period	$ 14,932	$ 21,211
Supplemental cash flow information:		
Cash payments for:		
Interest (net of capitalized interest)	$ 123,499	$ 125,262
Income taxes	72,940	1,294

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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
Operating revenues:				
Electric	$ 375,035	$ 322,669	$ 1,140,545	$ 1,018,256
Gas	111,042	89,432	594,737	484,603
Other	4,306	2,925	6,866	4,005
Total operating revenues	490,383	415,026	1,742,148	1,506,864
Operating expenses:				
Energy costs:				
Purchased electricity	200,861	147,589	587,983	517,803
Electric generation fuel	21,058	25,130	54,400	60,132
Residential exchange	(34,525)	(34,014)	(126,676)	(123,799)
Purchased gas	59,151	44,574	359,037	270,683
Unrealized net (gain) loss on derivative instruments	477	1,894	395	(1,042)
Utility operations and maintenance	81,645	67,093	240,299	214,149
Other operations and maintenance	425	277	925	850
Depreciation and amortization	60,550	57,598	178,284	170,036
Conservation amortization	5,633	4,747	16,746	17,746
Taxes other than income taxes	44,784	42,711	165,005	149,486
Income taxes	2,619	7,064	55,449	40,908
Total operating expenses	442,678	364,663	1,531,847	1,316,952
Operating income	47,705	50,363	210,301	189,912
Other income (deductions):				
Other income, net of tax	1,422	356	4,184	1,994
Interest charges:				
AFUDC	2,680	1,650	6,183	3,807
Interest expense	(45,614)	(42,699)	(130,083)	(128,639)
Mandatorily redeemable securities interest expense	(23)	(23)	(68)	(68)
Net income	$ 6,170	$ 9,647	$ 90,517	$ 67,006

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 SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2005	2004	2005	2004
Net income	$ 6,170	$ 9,647	$ 90,517	$ 67,006
Other comprehensive income, net of tax at 35%:				
Unrealized gains on derivative instruments during the period	37,896	17	48,484	11,577
Reversal of unrealized gains on derivative instruments settled during the period	(4,353)	(2,829)	(3,243)	(6,910)
Loss from settlement of cash flow hedge contracts	--	--	(22,960)	--
Amortization of cash flow hedge contracts to earnings	191	--	264	--
Deferral of cash flow hedges related to the power cost adjustment mechanism	(12,914)	(5,501)	(4,937)	(8,187)
Other comprehensive income (loss)	20,820	(8,313)	17,608	(3,520)
Comprehensive income	$ 26,990	$ 1,334	$ 108,125	$ 63,486

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

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

ASSETS

	SEPTEMBER 30, 2005	DECEMBER 31, 2004
Utility plant: (at original cost, including construction work in progress of $311,783 and $129,966, respectively)		
Electric	$ 4,645,289	$ 4,389,882
Gas	1,966,806	1,881,768
Common	436,822	409,677
Less: Accumulated depreciation and amortization	(2,566,492)	(2,452,969)
Net utility plant	4,482,425	4,228,358
Other property and investments	157,249	157,670
Current assets:		
Cash	9,816	12,955
Restricted cash	1,045	1,633
Accounts receivable, net of allowance for doubtful accounts	112,333	138,792
Unbilled revenue	81,265	140,391
Purchased gas adjustment receivable	37,508	19,088
Materials and supplies, at average cost	33,931	31,683
Fuel and gas inventory, at average cost	95,096	65,895
Unrealized gain on derivative instruments	203,419	14,791
Prepayments and other	33,875	6,247
Deferred income taxes	--	1,415
Total current assets	608,288	432,890
Other long-term assets:		
Regulatory asset for deferred income taxes	135,194	127,252
Regulatory asset for PURPA contract buyout costs	196,188	211,241
Unrealized gain on derivative instruments	38,956	21,315
Power cost adjustment mechanism	5,583	--
Other	383,141	401,030
Total other long-term assets	759,062	760,838
Total assets	$ 6,007,024	$ 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

	SEPTEMBER 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	612,769	609,467
Earnings reinvested in the business	162,110	138,678
Accumulated other comprehensive income (loss), net of tax at 35%	2,858	(14,750)
Total shareholder's equity	1,636,775	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	3,944,774	3,938,932
Current liabilities:		
Accounts payable	216,668	229,747
Short-term debt	223,871	--
Current maturities of long-term debt	46,000	31,000
Accrued expenses:		
Taxes	77,709	81,634
Salaries and wages	12,125	13,829
Interest	42,901	29,005
Unrealized loss on derivative instruments	14,643	26,581
Deferred income taxes	19,593	--
Tenaska disallowance reserve	--	3,156
Other	27,653	34,918
Total current liabilities	681,163	449,870
Long-term liabilities:		
Deferred income taxes	760,669	795,392
Unrealized loss on derivative instruments	--	385
Other deferred credits	620,418	395,177
Total long-term liabilities	1,381,087	1,190,954
Total capitalization and liabilities	$ 6,007,024	$ 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)

	NINE MONTHS ENDED SEPTEMBER 30,	
	2005	2004
Operating activities:		
Net income	$ 90,517	$ 67,006
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	178,284	170,036
Deferred income taxes and tax credits, net	(31,137)	65,498
Net unrealized (gain) loss on derivative instruments	395	(1,042)
Cash collateral received from energy suppliers	31,050	8,520
Increase in residential exchange program	4,984	8,452
Other	12,968	21,827
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	85,585	105,883
Materials and supplies	(2,249)	(3,499)
Fuel and gas inventory	(29,201)	(26.671)
Prepayments and other	(27,628)	(7,272)
Purchased gas adjustment receivable	(18,419)	(30,157)
Accounts payable	(13,080)	(52,514)
Taxes payable	(3,926)	(56,123)
Tenaska disallowance reserve	(3,156)	11,212
Accrued expenses and other	3,786	4,491
Net cash provided by operating activities	278,773	285,647
Investing activities:		
Construction expenditures - excluding equity AFUDC	(393,619)	(311,408)
Energy efficiency expenditures	(10,763)	(13,301)
Cash proceeds from property sales	15,830	672
Restricted cash	587	(1,240)
Refundable cash received for customer construction projects	10,221	9,497
Other	2,359	426
Net cash used by investing activities	(375,385)	(315,354)
Financing activities:		
Change in short-term debt, net	223,871	--
Dividends paid	(67,085)	(65,876)
Issuance of bonds	250,000	200,000
Settlement of cash flow hedge derivative on treasury rate lock	(34,776)	--
Redemption of trust preferred stock	(42,500)	--
Redemption of bonds and notes	(231,000)	(106,447)
Issuance and redemption cost of bonds and other	(5,037)	1,950
Net cash provided by financing activities	93,473	29,627
Net decrease in cash	(3,139)	(80)
Cash at beginning of year	12,955	14,778
Cash at end of period	$ 9,816	$ 14,698
Supplemental cash flow information:		
Cash payments for:		
Interest (net of capitalized interest)	$ 116,857	$ 120,615
Income taxes	75,482	1,294

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 (PUHCA) of 1935. The Energy Policy Act of 2005 repealed the PUHCA of 1935 effective February 8, 2006. Puget Energy owns Puget Sound Energy (PSE) and has a 90.9% ownership interest in InfrastruX Group, Inc. (InfrastruX). PSE is a public utility incorporated in the State of Washington and furnishes electric and gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region. InfrastruX is a non-regulated 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 into its regulated utility subsidiary, PSE. Management believes the 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 in 2005. Puget Energy is actively marketing InfrastruX and has held discussions with interested financial and strategic parties in 2005. Puget Energy has recently retained an investment banker to assist in the disposal of InfrastruX. To date, Puget Energy has not entered into a definitive agreement that would result in the sale of its investment in InfrastruX.

For the three and nine months ended September 30, 2005, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest) of $0.0 million and $0.9 million, respectively, compared to income of $1.7 million and $4.2 million (net of taxes and minority interest) for the three and nine months ended September 30, 2004, respectively. Included in the income for discontinued operations is a charge of $8.1 million after-tax for the three months ended September 30, 2005 and $14.3 million after-tax for the nine months ended September 30, 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. The following chart summarizes

Puget Energy's income from discontinued operations for the three and nine months ended September 30, 2005:

(DOLLARS IN MILLIONS)	THREE MONTHS ENDED SEPTEMBER 30, 2005	NINE MONTHS ENDED SEPTEMBER 30, 2005
Net income reported by InfrastruX	$ 5.3	$ 7.8
InfrastruX depreciation and amortization not recorded by Puget Energy, net of tax	2.9	7.3
Puget Energy tax benefit from goodwill deduction	0.7	1.4
Puget Energy carrying value adjustment of InfrastruX, including cost of sale, net of tax	(8.1)	(14.3)
Minority interest in income from discontinued operations and other	(0.8)	(1.3)
Income from discontinued operations	$ --	$ 0.9

InfrastruX's bank and vendor debt under its credit agreements totaled $151.6 million at September 30, 2005 compared to $159.4 million at December 31, 2004 and $181.3 million at September 30, 2004. In May 2004, InfrastruX signed a three-year agreement with a group of banks to provide up to $150 million in financing, with Puget Energy as guarantor. Certain InfrastruX subsidiaries also have borrowing capacities for working capital purposes of which Puget Energy is not the guarantor. Of the $150 million bank facility available to InfrastruX, $121 million was outstanding at September 30, 2005 and $131 million was outstanding at December 31, 2004. In determining the fair value of its InfrastruX investment, Puget Energy has determined proceeds of a sale will first be used to extinguish all outstanding InfrastruX debt.

In accordance with SFAS No. 144, Puget Energy has adjusted the carrying value of its investment in InfrastruX to the estimate of fair value, less cost to sell, at September 30, 2005. This estimate could change based on InfrastruX's financial performance and market conditions in the utility constructions services sector. After reflecting an $8.1 million carrying value reduction in the third quarter 2005 and $14.3 million for the nine months ended September 30, 2005, Puget Energy's equity investment in InfrastruX was $34.3 million at September 30, 2005. It is not anticipated that any funding will be needed from Puget Energy to maintain operations at InfrastruX or to complete the sale transaction.

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

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
(DOLLARS IN THOUSANDS)	2005	2004	2005	2004
Revenues	$ 111,667	$ 99,925	$ 286,665	$ 267,496
Operating expenses (including interest expense)	(106,180)	(96,519)	(276,267)	(259,166)
Pre-tax income	5,487	3,406	10,398	8,330
Income tax expense	(4,684)	(1,567)	(7,986)	(3,685)
Minority interest in income of discontinued operations	(804)	(162)	(1,504)	(408)
Income (loss) from discontinued operations	$ (1)	$ 1,677	$ 908	$ 4,237

In accordance with SFAS No. 144, InfrastruX discontinued depreciation and amortization of its assets effective February 8, 2005. This discontinuation of depreciation and amortization resulted in $4.7 million ($2.9 million after-tax) and $12 million ($7.3 million after-tax) lower depreciation and amortization expense than otherwise would have been recorded as continuing operations for the three and nine months ended September 30, 2005, respectively.

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

(DOLLARS IN THOUSANDS)	SEPTEMBER 30, 2005	DECEMBER 31, 2004
Assets:		
Cash	$ 5,115	$ 6,817
Accounts receivable	93,064	78,646
Other current assets	24,485	25,459
Total current assets	122,664	110,922
Goodwill	43,886	43,503
Intangibles	15,167	16,680
Non-utility property and other	102,700	100,115
Total long-term assets	161,753	160,298
Total assets	$ 284,417	$ 271,220
Liabilities:		
Accounts payable	$ 10,314	$ 9,773
Short-term debt	15,281	8,297
Current maturities of long-term debt	6,566	7,933
Other current liabilities	41,622	25,889
Total current liabilities	73,783	51,892
Deferred income taxes	22,641	25,828
Long-term debt	129,786	143,172
Other deferred credits	20,614	14,710
Total long-term liabilities	173,041	183,710
Total liabilities	$ 246,824	$ 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 100,371,000 and 100,160,000 for the three and nine months ended September 30, 2005, respectively, and 99,580,000 and 99,373,000 for the three and nine months ended September 30, 2004, respectively.

Puget Energy's diluted earnings per common share have been computed based on weighted average common shares outstanding of 100,964,000 and 100,754,000 for the three and nine months ended September 30, 2005, respectively, and 100,043,000 and 99,836,000 for the three and nine months ended September 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 contracts requiring physical delivery of electricity and natural gas 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 portfolio of owned and contracted electric generation resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the

PCA. The Company's energy risk 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 price risk exposure. The third priority is to optimize the value of excess capacity or flexibility within the energy portfolio. The Company is not engaged in the business of assuming risk for the purpose of realizing 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 advisable 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 September 30, 2005, the Company recorded a decrease in earnings for the change in the market value of derivative instruments not meeting cash flow hedge criteria of approximately $0.5 million compared to a decrease in earnings of approximately $1.9 million for the three months ended September 30, 2004. At September 30, 2005, the Company had a net unrealized gain recorded in other comprehensive income of $33.8 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. At September 30, 2005, PSE had a short-term asset of $51.9 million related to energy contracts designated as cash flow hedges that represent forward financial purchases of gas supply for electric generation of PSE-owned electric plants in future periods. If it is determined that it is uneconomical to run the plants in the future period, the hedging relationship is ended and the cash flow hedge is de-designated and any unrealized gains and losses are recorded in the income statement. Gains and losses, when these de-designated cash flow hedges are settled, are recognized in energy costs and are included as part of the PCA mechanism. Due to high forward market prices at the end of September 2005, sizeable unrealized gains have resulted in cash flow hedge assets for the period.

At September 30, 2005, the Company also has a short-term asset of approximately $133.4 million related to the cash flow hedge of gas contracts to serve natural gas customers. The third quarter 2005 saw market gas prices spike in part due to the impact of hurricane damage in the gulf coast region in the United States which affected supply, therefore existing gas financial hedges showed sizeable unrealized gains when marked to the higher market prices. All mark-to-market adjustments relating to the natural gas business have been reclassified to a deferred account in accordance with SFAS No. 71 due to the PGA mechanism. The PGA mechanism passes on to customers increases and decreases in the cost of natural gas supply. As the gains and losses on the cash flow hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism.

During the nine months ended September 30, 2005, the Company recorded a decrease in earnings for the change in the market value of derivative instruments not meeting cash flow hedge criteria of approximately $0.4 million compared to an increase in earnings of approximately $1.0 million for the nine months ended September 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 September 30, 2005, the Company recorded a liability associated with these two contracts in the amount of $0.8 million and an unrealized loss in the amount of $0.5 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 $250.0 million that was completed in May 2005. Since treasury interest rates related to the hedged debt decreased from the date of issuance of the treasury lock instruments, PSE paid the counterparties $35.3 million for the change in bond value when the contracts were settled. In addition, the bonds issued associated with the treasury lock instruments had a correspondingly lower interest rate since treasury rates decreased from the date of issuance of the treasury lock instruments. The treasury lock contracts were designated and documented under SFAS No. 133 criteria as cash flow hedges, with all changes in market value for each reporting period being presented net of tax in other comprehensive income. In the second quarter 2005, the settlement loss on these instruments amounted to $23.0 million, after-tax, and was recorded as a loss in other comprehensive income. In accordance with SFAS No. 133, this loss is being amortized out of other comprehensive income to current earnings as an increase to interest expense over the life of the new debt issued at an annual rate of approximately $1.2 million pre-tax. The ending balance in other comprehensive income related to the treasury lock contracts at September 30, 2005 was a loss of $22.7 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 additional asset retirement obligations related to unprotected bare steel gas pipe and leases to operate wind turbine generators. 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; (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; and (6) to remove wind turbine generators and related equipment, improvements and fixtures at the termination of the related leases. The replacement of bare steel natural gas pipe and the future removal of the wind generators are the additional asset retirement obligations liabilities recognized in 2005.

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

(DOLLARS IN THOUSANDS) AT SEPTEMBER 30	2005	2004
Asset retirement obligation at beginning of year	$ 3,516	$ 3,421
New ARO liability recognized in the period	2,538	--
Liability settled in the period	(321)	--
Accretion expense	141	71
Asset retirement obligation at September 30	$ 5,874	$ 3,492

In March 2005, FASB issued FIN 47 which provided guidance on when an asset retirement obligation, that is conditional on a future event, should be recognized. The Company will adopt FIN 47 in the fourth quarter 2005. See Note 9 for further explanation.

(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:

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	2005	2004	2005	2004
Net income, as reported	$ 5,911	$ 11,124	$ 90,881	$ 70,710
Add: Total stock-based employee compensation expense included in net income, net of tax	995	904	2,800	2,474
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(992)	(860)	(2,891)	(2,301)
Pro forma net income	$ 5,914	$ 11,168	$ 90,790	$ 70,883
Earnings per share:				
Basic per common share as reported	$ 0.06	$ 0.11	$ 0.91	$ 0.71
Diluted per common share as reported	$ 0.06	$ 0.11	$ 0.90	$ 0.71
Basic per common share pro forma	$ 0.06	$ 0.11	$ 0.91	$ 0.71
Diluted per common share pro forma	$ 0.06	$ 0.11	$ 0.90	$ 0.71

In December 2004, FASB issued SFAS No. 123R, "Share-Based Payments," which revises SFAS No. 123. The Company will implement SFAS No. 123R for periods commencing January 1, 2006. See Note 9 for further explanation.

(7) Retirement Benefits

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

	PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2005	2004	2005	2004
Service cost	$ 2,915	$ 2,586	$ 49	$ 42
Interest cost	5,979	6,021	344	376
Expected return on plan assets	(9,482)	(9,777)	(220)	(200)
Amortization of prior service cost	756	797	77	78
Recognized net actuarial (gain) loss	814	282	(115)	(179)
Amortization of transition (asset) obligation	(41)	(276)	105	104
Net periodic benefit cost (income)	$ 941	$ (367)	$ 240	$ 221

The following summarizes the net periodic benefit cost for the nine months ended September 30:

(DOLLARS IN THOUSANDS)	PENSION BENEFITS 2005	PENSION BENEFITS 2004	OTHER BENEFITS 2005	OTHER BENEFITS 2004
Service cost	$ 8,745	$ 7,757	$ 139	$ 142
Interest cost	17,937	18,062	939	1,252
Expected return on plan assets	(28,446)	(29,330)	(659)	(644)
Amortization of prior service cost	2,268	2,392	233	232
Recognized net actuarial (gain) loss	2,443	846	(529)	(179)
Amortization of transition (asset) obligation	(122)	(828)	313	314
Net periodic benefit cost (income)	$ 2,825	$ (1,101)	$ 436	$ 1,117

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 nine months ended September 30, 2005, the actual cash contributions to the pension plans were $0.3 million and $1.2 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 $0.3 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 nine months ended September 30, 2005, actual other post-retirement medical benefit plan contributions were $0.1 million and $1.1 million, respectively. In the third quarter, the Company's expected contributions to the post-retirement medical benefit plan for 2005 was revised from $1.4 million to $1.0 million. As the Company has already made payments of $1.0 million for the nine months ended September 30, 2005, it does not expect to make additional contributions during the last three months of 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 nine months ended September 30, 2005 for the 2005 plan year by $0.6 million.

(8) Other

At September 30, 2005, PSE had a net receivable totaling $21.3 million in connection with wholesale sales in 2000 to the California Independent System Operator (CAISO) and counterparties where payment to PSE was conditioned on the counterparties being paid by the California Power Exchange. In August 2005, PSE submitted a Fuel Cost Adjustment Claim for $3.4 million related to sales in 2000 to the CAISO, pursuant to FERC's California refund proceeding.

Pursuant to an order issued by FERC in August 2005, PSE also submitted a Portfolio Cost Claim in September 2005 for $9.3 million to the CAISO. FERC has not yet clarified several important computational issues with these types of claims, nor has it determined a mechanism for the allocation and payment of Portfolio Cost Claim and Fuel Cost Adjustment Claim. PSE's ability to recover all or a portion of these claims is uncertain at the present time.

Based upon FERC orders, PSE has determined a range related to its CAISO receivable to be between $21.3 million (PSE's net receivable balance) and $34.2 million including interest on its past due receivables as of September 30, 2005.

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

On October 18, 2005, PSE learned of two additional potential royalty claims that are likely to be asserted by the State of Montana in the near future. The potential claims, in total, amount to $0.3 million, plus interest. PSE's initial assessment of these claims is that they would likely have a similar ultimate result to the parallel MMS claims that are being appealed. If the State of Montana's claims are asserted, PSE will defend them consistently with the MMS claims. PSE reserved $1.1 million for the MMS claim in the second quarter of 2004.

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 September 30, 2005 and 2004 for these three entities was $73.2 million and $70.9 million, respectively. PSE's Purchased Electricity expense for the nine months ended September 30, 2005 and 2004 for these three entities was $186.7 million and $180.9 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. The NOPA states that the deduction was not valid for the 2003 tax year and would require repayment of approximately $14.5 million in tax. Management of Puget Energy believes the deduction is valid and intends to vigorously defend the deduction, however the outcome of this issue cannot be predicted. Any potential tax related payment (excluding interest) would have no impact on earnings as it would be recognized as a deferred tax asset. If the Company is unsuccessful, a charge for interest expense could apply.

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

Due to the new Regulations, PSE filed on October 19, 2005 an accounting petition with the Washington Commission to defer cost using PSE's allowed net of tax rate of return of 7.01% associated with increasing capital borrowing necessary to repay $72 million in income tax that was treated as a reduction to rate base in the Washington Commission order of February 18, 2005, beginning November 1, 2005. This accounting petition was approved by the Washington Commission on October 26, 2005, for deferral of additional capital costs beginning November 1, 2005. PSE will request recovery of this deferral commencing January 2007 in its February 2006 electric general rate case filing.

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

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

In October 2005, PSE completed the issuance of $150 million of senior notes secured by first mortgage bonds, at a rate of 5.197%, due October 1, 2015. The net proceeds from the issuance of the senior notes of approximately $149 million were used to repay a portion of PSE’s short-term debt.

On October 26, 2005, Puget Energy agreed to sell 15 million shares of common stock to Lehman Brothers Inc. The net proceeds of approximately $309.8 million were invested in PSE and used to repay short-term debt incurred to primarily fund PSE’s construction program. In addition, Lehman Brothers has a 30 day option to purchase up to an additional 1.7 million shares of Puget Energy common stock if the underwriter sells more than 15 million shares in the offering.

(9) 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, which will be January 1, 2006 for the Company. 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. **<u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>**

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. Puget Energy's ability to complete the sale of InfrastruX to a third party on reasonable terms is subject to a number of factors beyond our control. See section titled "InfrastruX" for further discussion.

<u>PUGET SOUND ENERGY</u>

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 energy market. PSE is continually exploring new electric-power resource generation and long-term purchase power agreements to meet this goal. The completion of its acquisitions of the Hopkins Ridge wind project in the first quarter 2005 and the Wild Horse wind project in the third quarter is one step in reaching this goal. In the first quarter 2005, PSE issued notice to proceed with construction of the Hopkins Ridge wind project which is expected to be completed by the end of 2005. The Hopkins Ridge wind project will provide approximately 150 MW of capacity or 52 average MW. PSE also issued notice to proceed with construction of the Wild Horse wind project in the third quarter 2005 which is expected to be completed by the end of 2006. The Wild Horse wind project will provide approximately 230 MW of capacity or 73 average MW. Combined, these projects will require approximately $570 million in capital requirements in 2005 and 2006. Together these electric generation resources will serve the needs of approximately 123,000 of PSE's electric customers.

The Hopkins Ridge wind project and the Wild Horse wind project were included as part of PSE's energy resource portfolio in its long-term electric Least Cost Plan that was filed May 2, 2005 with the Washington Commission. The plan supports a strategy of diverse resource acquisitions including resources fueled by natural gas and coal, renewable resources and shared resources. The Least Cost Plan was followed by issuing an all-source request for proposal (RFP) on November 1, 2005. PSE obtained approval of the all-source RFP from the Washington Commission on October 28, 2005.

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 September 30, 2005 was $5.9 million on operating revenues of $490.4 million from continuing operations compared to net income of $11.1 million on operating revenues of $415.0 million from continuing operations for the same period in 2004. The net income for both periods includes the results of discontinued operations for InfrastruX.

Basic and diluted earnings per share for the three months ended September 30, 2005 were $0.06 compared to basic and diluted earnings per share for the three months ended September 30, 2004 of $0.11. Discontinued operations and loss on disposal of InfrastruX had no effect on the basic and diluted earnings per share for the three months ended September 30, 2005. Included in the basic and diluted earnings per share for the three months ended September 30, 2004 was $0.02 earnings per share related to discontinued operations of InfrastruX.

Net income for the three months ended September 30, 2005 was positively impacted by increased gas margins of $4.4 million compared to the same period in 2004 related to the effects of increased gas usage and the gas general rate case which increased margins by $2.4 million. Higher planned maintenance costs at PSE-owned energy production facilities, delivery infrastructure and employee pension and benefit costs negatively impacted net income. Also negatively impacting net income was higher depreciation and amortization expense on PSE's transmission and distribution system infrastructure projects.

For the nine months ended September 30, 2005, Puget Energy's net income was $90.9 million on operating revenues of $1.7 billion compared to net income of $70.7 million on operating revenues of $1.5 billion for the same period in 2004. Basic and diluted earnings per share for the nine months ended September 30, 2005 were $0.91 and $0.90, respectively, compared to basic and diluted earnings per share of $0.71 for the same period in 2004. Included in the basic and diluted earnings per share for the nine months ended September 30, 2005 was $0.01 earnings per share related to discontinued operations and loss on disposal of InfrastruX compared to $0.04 basic and diluted earnings per share related to discontinued operations of InfrastruX for the same period in 2004.

Net income for the nine months ended September 30, 2005 was positively impacted by increased electric and gas margins of $51.6 million and $9.0 million, respectively, compared to the same period in 2004, mainly due to the Tenaska disallowance in May 2004, increased electric and gas usage and increase in gas general rates offset by a one-time true-up of previously reported purchased gas costs.

The Tenaska disallowance in May 2004 relates to an order in May 2004 in which the Washington Utilities and Transportation Commission (Washington Commission) determined that PSE did not prudently manage gas costs for the Tenaska electric generating plant and ordered PSE to adjust its deferral account by expensing a one-time charge to purchased electricity. The order also established guidelines for future recovery of Tenaska costs. See further discussion under section titles "Other" – "Tenaska Disallowance".

PUGET SOUND ENERGY

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

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 September 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 SEPTEMBER 30	ELECTRIC MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Electric retail sales revenue	$ 315.3	$ 293.7	$ 21.6	7.4 %
Electric transportation revenue	1.7	2.7	(1.0)	(37.0)%
Other electric revenue-gas supply resale	9.1	1.6	7.5	468.8 %
Total electric revenue for margin[1]	326.1	298.0	28.1	9.4 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(6.5)	(5.3)	(1.2)	(22.6)%
Pass-through revenue-sensitive taxes	(23.2)	(21.3)	(1.9)	(8.9)%
Residential exchange credit	34.5	34.0	0.5	1.5 %
Net electric revenue for margin	330.9	305.4	25.5	8.3 %
Minus power costs:				
Electric generation fuel	(21.0)	(25.1)	4.1	16.3 %
Purchased electricity, net of sales to other utilities and marketers[2]	(160.2)	(133.4)	(26.8)	(20.1)%
Total electric power costs[3]	(181.2)	(158.5)	(22.7)	(14.3)%
Electric margin before PCA	149.7	146.9	2.8	1.9 %
Tenaska disallowance reserve	--	2.4	(2.4)	*
Power cost deferred under the PCA mechanism	--	--	--	--
Electric margin[4]	$ 149.7	$ 149.3	$ 0.4	0.3 %

**Percent change not applicable or unmeaningful.*

[1] *For the three months ended September 30, 2005, total electric revenue for margin was $326.1 million, which does not include $40.6 million in sales to other utilities and marketers and $8.3 million in other miscellaneous electric revenue included in electric operating revenues of $375.0 million. For the three months ended September 30, 2004, total electric revenue for margin was $298.0 million, which does not include $16.6 million in sales to other utilities and marketers and $8.1 million in other miscellaneous electric revenues included in electric operating revenues of $322.7 million.*

[2] *For the three months ended September 30, 2005, purchased electricity, net of sales to other utilities and marketers, was $160.2 million, excluding sales to other utilities and marketers of $40.7 million, purchased electricity was $200.9 million. For the three months ended September 30, 2004, purchased electricity, net of sales to other utilities and marketers, was $133.4 million ,excluding sales to other utilities and marketers of $16.6 million and deducting the Tenaska disallowance reserve of $(2.4) million, purchased electricity was $147.6 million.*

[3] *For the three months ended September 30, 2005, total electric power costs were $181.2 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(34.5) million and unrealized net loss on derivative instruments of $0.5 million. These amounts, excluding sales of electricity to other utilities and marketers, provide electric energy costs of $187.9 million. For the three months ended September 30, 2004, total electric power costs were $158.5 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(34.0) million and unrealized net loss on derivative instruments of $1.9 million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $140.6 million.*

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

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

(Dollars in Millions) Nine Months Ended September 30	Electric Margin 2005	2004	Change	Percent Change
Electric retail sales revenue	$ 1,018.9	$ 942.1	$ 76.8	8.2 %
Electric transportation revenue	6.7	7.3	(0.6)	(8.2)%
Other electric revenue-gas supply resale	14.3	5.6	8.7	155.4 %
Total electric revenue for margin[1]	1,039.9	955.0	84.9	8.9 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(19.0)	(19.4)	0.4	2.1 %
Pass-through revenue-sensitive taxes	(75.4)	(68.3)	(7.1)	(10.4)%
Residential exchange credit	126.7	123.8	2.9	2.3 %
Net electric revenue for margin	1,072.2	991.1	81.1	8.2 %
Minus power costs:				
Electric generation fuel	(54.4)	(60.1)	5.7	9.5 %
Purchased electricity, net of sales to other utilities and marketers[2]	(522.5)	(464.2)	(58.3)	(12.6)%
Total electric power costs[3]	(576.9)	(524.3)	(52.6)	(10.0)%
Electric margin before PCA	495.3	466.8	28.5	6.1 %
Tenaska disallowance reserve	5.3	(34.1)	39.4	* %
Power cost deferred under the PCA mechanism	3.0	19.3	(16.3)	(84.5)%
Electric margin[4]	$ 503.6	$ 452.0	$ 51.6	11.4 %

**Percent change not applicable or unmeaningful.*

1 *For the nine months ended September 30, 2005, total electric revenue for margin was $1,039.9 million, which does not include $73.8 million in sales to other utilities and marketers and $26.8 million in other miscellaneous electric revenue included in electric operating revenues of $1,140.5 million. For the nine months ended September 30, 2004, total electric revenue for margin was $955.0 million, which does not include $38.8 million in sales to other utilities and marketers and $24.5 million in other miscellaneous electric revenues included in electric operating revenues of $1,018.3 million.*

2 *For the nine months ended September 30, 2005, purchased electricity, net of sales to other utilities and marketers, was $522.5 million excluding sales to other utilities and marketers of $73.8 million and including the Tenaska disallowance of $(5.3) million and power cost deferral under the PCA mechanism of $(3.0) million, purchased electricity was $588.0 million. For the nine months ended September 30, 2004, purchased electricity, net of sales to other utilities and marketers, was $464.2 million, excluding sales to other utilities and marketers of $38.8 million and including the Tenaska disallowance of $34.1 million and the power cost deferral under the PCA mechanism of $(19.3) million, purchased electricity was $517.8 million.*

3 *For the nine months ended September 30, 2005, total electric power costs were $576.9 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(126.7) million and unrealized net loss on derivative instruments of $0.4 million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $516.1 million. For the nine months ended September 30, 2004, total electric power costs were $524.3 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(123.8) million and unrealized net gain on derivative instruments of $(1.0) million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $453.1 million.*

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

Electric margin increased $0.4 million for the three months ended September 30, 2005 compared to the same period in 2004. The electric general rate case for the three months ended September 30, 2005 increased electric revenues but were offset by additional recovery of power costs through the Power Cost Adjustment (PCA) mechanism which does not increase margin. Retail customer kWh sales (residential, commercial and industrial customers) increased 1.5% for the three months ended September 30, 2005 compared to 2004.

Electric margin increased $51.6 million for the nine months ended September 30, 2005 compared to the same period in 2004 primarily as a result of the one-time Tenaska disallowance recorded in May 2004, and ongoing Tenaska disallowance, which reduced margin by $34.1 million for the nine months ended September 30, 2004. In February 2005, a final resolution and recovery of a $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 2.2% increase in retail customer usage, and change in customer class usage, which contributed $33.3 million to margin. These increases were partially offset by a reduction in customer deferral of excess power costs in 2005 under the PCA mechanism which provided recovery of power costs for the nine months ended September 30, 2005 compared to the same period in 2004. Electric margin for the nine months ended September 30, 2005 was also affected by the ongoing Tenaska disallowance applicable to periods after May 24, 2004 which increased $3.7 million as compared to the same period in 2004.

The following table displays the details of gas margin changes for the three months ended September 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 SEPTEMBER 30	GAS MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 103.7	$ 83.0	$ 20.7	24.9 %
Gas transportation revenue	3.3	3.1	0.2	6.5 %
Total gas revenue for margin[1]	107.0	86.1	20.9	24.3 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(0.6)	(0.4)	(0.2)	(50.0)%
Pass-through revenue-sensitive taxes	(8.5)	(6.8)	(1.7)	(25.0)%
Net gas revenue for margin	97.9	78.9	19.0	24.1 %
Minus purchased gas costs	(59.2)	(44.6)	(14.6)	(32.7)%
Gas margin[2]	$ 38.7	$ 34.3	$ 4.4	12.8 %

[1] *For the three months ended September 30, 2005, total gas revenue for margin was $107.0 million, which does not include $4.0 million related to other gas operating revenues that is included in gas operating revenues of $111.0 million. For the three months ended September 30, 2004, total gas revenue for margin was $86.1 million, which does not include $3.3 million related to other gas operating revenues that is included in gas operating revenues of $89.4 million.*

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

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

(DOLLARS IN MILLIONS) NINE MONTHS ENDED SEPTEMBER 30	GAS MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 571.8	$ 465.0	$ 106.8	23.0 %
Gas transportation revenue	9.9	9.7	0.2	2.1 %
Total gas revenue for margin[1]	581.7	474.7	107.0	22.5 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(3.5)	(2.0)	(1.5)	(75.0)%
Pass-through revenue-sensitive taxes	(47.2)	(39.0)	(8.2)	(21.0)%
Net gas revenue for margin	531.0	433.7	97.3	22.4 %
Minus purchased gas costs[2]	(359.0)	(270.7)	(88.3)	(32.6)%
Gas margin[3]	$ 172.0	$ 163.0	$ 9.0	5.5 %

[1] *For the nine months ended September 30, 2005, total gas revenue for margin was $581.7 million, which does not include $13.0 million related to other gas operating revenues that is included in gas operating revenues of $594.7 million. For the nine months ended September 30, 2004, total gas revenue for margin was $474.7 million, which does not include $9.9 million related to other gas operating revenues that is included gas operating revenues of $484.6 million.*

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

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

Gas margin increased $4.4 million for the three months ended September 30, 2005 compared to the same period in 2004 primarily due to increased gas general tariff rates and increased usage by customers. Gas margin increased $2.4 million as a result of the gas general tariff increase effective March 4, 2005. Therm sales increased 1.3% for the three months ended September 30, 2005 compared to the same period in 2004, which provided $2.0 million to gas margin.

Gas margin increased $9.0 million for the nine months ended September 30, 2005 compared to the same period in 2004. Gas margin increased $8.6 million as a result of the gas general tariff rate case. In addition, therm sales increased 0.8% for the nine months ended September 30, 2005 compared to the same period in 2004, which provided $1.3 million to gas margin, and changes in customer class usage provided $4.0 million to gas margin. Negatively impacting gas margin for the nine months ended September 30, 2005, was a $5.0 million one-time true-up of previously reported gas costs under the PGA mechanism in the second quarter. See further discussion under the section titled "Operating Expenses-Purchased Gas." In addition, warmer than normal temperatures in PSE's service territory in the first and second quarters have adversely impacted sales volumes for natural gas.

ELECTRIC OPERATING REVENUES

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

(DOLLARS IN MILLIONS) THREE MONTHS ENDED SEPTEMBER 30	2005	2004	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 131.7	$ 122.4	$ 9.3	7.6 %
Commercial sales	153.1	143.7	9.4	6.5 %
Industrial sales	23.7	22.2	1.5	6.8 %
Other retail sales, including unbilled revenue	6.8	5.4	1.4	25.9 %
Total retail sales	315.3	293.7	21.6	7.4 %
Transportation sales	1.7	2.7	(1.0)	(37.0) %
Sales to other utilities and marketers	40.6	16.6	24.0	144.6 %
Other	17.4	9.7	7.7	79.4 %
Total electric operating revenues	$ 375.0	$ 322.7	$ 52.3	16.2 %

Electric retail sales increased $21.6 million for the three months ended September 30, 2005 compared to the same period in 2004 due primarily to the electric general rate case and increased retail customer usage. The electric general rate case provided $12.8 million to electric operating revenues for the three months ended September 30, 2005 compared to the same period in 2004. Retail electricity usage increased 68,279 MWh or 1.5% for the three months ended September 30, 2005 compared to the same period in 2004, which resulted in an approximate $4.5 million increase in electric operating revenue. The increase in electricity usage was primarily the result of a 1.8% increase in the average number of customers served.

During the three month period ended September 30, 2005, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $36.2 million compared to $35.3 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 $24.0 million compared to the three month period ended September 30, 2004 primarily due to an increase of 326,313 MWh sold related to excess energy available for sale on the wholesale market. This resulted primarily from normal streamflows for hydro electric generation in the quarter instead of below normal streamflows that were expected. The increase in MWh sold was due to differences in timing of the need for power to serve base load and actual weather conditions. Sales to other utilities and marketers are included in the PCA mechanism as a reduction in determining net power costs.

Other electric revenues increased $7.7 million for the three months ended September 30, 2005 compared to the same period in 2004, primarily from the sale of excess non-core gas purchased for intended electric generation. Non-core gas sales are included in the PCA mechanism calculation as a reduction in determining net power costs.

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

(Dollars in Millions) Nine Months Ended September 30	2005	2004	Change	Percent Change
Electric operating revenues:				
Residential sales	$ 496.5	$ 459.1	$ 37.4	8.1 %
Commercial sales	461.1	428.9	32.2	7.5 %
Industrial sales	68.9	65.3	3.6	5.5 %
Other retail sales, including unbilled revenue	(7.6)	(11.2)	3.6	32.1 %
Total retail sales	1,018.9	942.1	76.8	8.2 %
Transportation sales	6.7	7.3	(0.6)	(8.2)%
Sales to other utilities and marketers	73.8	38.8	35.0	90.2 %
Other	41.1	30.1	11.0	36.5 %
Total electric operating revenues	$ 1,140.5	$ 1,018.3	$ 122.2	12.0 %

Electric retail sales increased $76.8 million for the nine months ended September 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 $28.6 million to electric operating revenues for the nine months ended September 30, 2005 compared to the same period in 2004, which provided approximately $20.3 million in electric operating revenues. Retail electricity usage increased 311,785 MWh or 2.2% for the nine months ended September 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 nine month period ended September 30, 2005 compared to the same period in 2004.

During the nine months ended September 30, 2005, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $132.6 million compared to $129.2 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 $35.0 million compared to the nine months ended September 30, 2004 primarily due to an increase of 567,957 MWh sold related to excess generation and energy available for sale on the wholesale market. This resulted primarily from normal streamflows for hydro electric generation in the third quarter as compared to below normal streamflows that were expected. The increase in MWh sold was due to differences in timing of the need for power to serve base load and actual weather conditions.

Other electric revenues increased $11.0 million for the nine months ended September 30, 2005 compared to the same period in 2004, primarily from the sale of excess non-core gas purchased for intended electric generation. Non-core gas sales are included in the PCA mechanism calculation as a reduction in determining net power costs.

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

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

GAS OPERATING REVENUES

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

(DOLLARS IN MILLIONS) THREE MONTHS ENDED SEPTEMBER 30	2005	2004	CHANGE	PERCENT CHANGE
Gas operating revenues:				
Residential sales	$ 57.3	$ 47.1	$ 10.2	21.7 %
Commercial sales	37.2	29.0	8.2	28.3 %
Industrial sales	9.2	6.9	2.3	33.3 %
Total retail sales	103.7	83.0	20.7	24.9 %
Transportation sales	3.3	3.1	0.2	6.5 %
Other	4.0	3.3	0.7	21.2 %
Total gas operating revenues	$ 111.0	$ 89.4	$ 21.6	24.2 %

Gas retail sales increased $20.7 million for the three months ended September 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 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 September 30, 2005, the effects of the PGA mechanism rate increases provided an increase of $13.8 million in gas operating revenues. In addition, the gas general rate case increased gas rates by 3.5%, which provided an additional $2.4 million in gas operating revenue for the three months ended September 30, 2005 compared to the same period in 2004. An increase of 2.9% in the average number of customers increased customer usage by 2.7 million therms or approximately $2.5 million in gas operating revenues.

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

(DOLLARS IN MILLIONS) NINE MONTHS ENDED SEPTEMBER 30	2005	2004	CHANGE	PERCENT CHANGE
Gas operating revenues:				
Residential sales	$ 360.7	$ 295.4	$ 65.3	22.1 %
Commercial sales	178.9	144.2	34.7	24.1 %
Industrial sales	32.2	25.4	6.8	26.8 %
Total retail sales	571.8	465.0	106.8	23.0 %
Transportation sales	9.9	9.7	0.2	2.1 %
Other	13.0	9.9	3.1	31.3 %
Total gas operating revenues	$ 594.7	$ 484.6	$ 110.1	22.7 %

Gas retail sales increased $106.8 million for the nine months ended September 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 $81.8 million in gas revenues for the nine months ended September 30, 2005 compared to the same period in 2004. In addition, the gas general rate case increase provided an additional $8.6 million in gas operating revenues for the nine months ended September 30, 2005 compared to the same period in 2004. An increase of 3.1% in the average number of customers for the nine months ended September 30, 2005 provided the remaining increase in retail gas revenues 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	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
PGA	October 1, 2004	17.6 %	$ 121.7
Gas General Rate Case	March 4, 2005	3.5 %	26.3
PGA	October 1, 2005	14.7 %	121.6

Operating Expenses

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

(Dollars in Millions) Three Months Ended September 30	2005	2004	Change	Percent Change
Purchased electricity	$ 200.9	$ 147.6	$ 53.3	36.1 %
Electric generation fuel	21.1	25.1	(4.0)	(15.9)%
Purchased gas	59.2	44.6	14.6	32.7 %
Unrealized (gain) loss on derivative instruments	0.5	1.9	(1.4)	(73.7)%
Utility operations and maintenance	81.6	67.1	14.5	21.6 %
Depreciation and amortization	60.6	57.6	3.0	5.2 %
Taxes other than income taxes	44.8	42.7	2.1	4.9 %
Income taxes	2.6	7.1	(4.5)	(63.4)%

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

(Dollars in Millions) Nine Months Ended September 30	2005	2004	Change	Percent Change
Purchased electricity	$ 588.0	$ 517.8	$ 70.2	13.6 %
Electric generation fuel	54.4	60.1	(5.7)	(9.5)%
Residential exchange credit	(126.7)	(123.8)	2.9	2.3 %
Purchased gas	359.0	270.7	88.3	32.6 %
Unrealized (gain) loss on derivative instruments	0.4	(1.0)	1.4	140.0 %
Utility operations and maintenance	240.3	214.1	26.2	12.2 %
Depreciation and amortization	178.3	170.0	8.3	4.9 %
Taxes other than income taxes	165.0	149.5	15.5	10.4 %
Income taxes	55.4	40.9	14.5	35.5 %

Purchased electricity expenses increased $53.3 million and $70.2 million for the three and nines months ended September 30, 2005, respectively, compared to the same periods in 2004. The increase for the three months ended September 30, 2005 was primarily the result of lower generation of power at PSE-controlled facilities, higher wholesale market prices and higher customer usage, which increased the amount of power purchased. Total purchased power for the three months ended September 30, 2005 increased 532,685 MWh or 14.7% compared to the same period in 2004. Generation at PSE-controlled facilities decreased 148,463 MWh or 7.7% compared to the same period in 2004. The increase for the nine months ended September 30, 2005 was the result of increased power purchases and higher wholesale market prices offset by a one-time $37.8 million disallowance charge related to the return on the Tenaska gas supply regulatory asset in 2004. Total purchased power for the nine months ended September 30, 2005 increased 1,086,551 MWh, or a 9.5% 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 nine months ended September 30, 2005.

PSE's hydroelectric production and related power costs in 2005 and 2004 have continued to be negatively impacted by below-normal precipitation and reduced snow pack in the Pacific Northwest region. The July 8, 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 September 2005 would be 86% of normal, which compares to 84% 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 regulated power portfolio through short-term and intermediate-term off-system physical purchases and sales, and through other risk management techniques.

Electric generation fuel expense decreased $4.0 million and $5.7 million for the three and nine months ended September 30, 2005, respectively, compared to the same periods in 2004. The decrease for the three months ended September 30, 2005 is primarily related to lower generation at PSE-controlled combustion turbine generating facilities of 82,087 MWhs and overall lower cost of gas for those facilities due to hedging of gas supply costs for a decrease of $5.5 million. Offsetting the decrease is an increase of $1.4 million in the cost of coal due to higher generation at Colstrip generating facilities of 49,225 MWhs and an increase in the price of the fuel. The decrease for the nine months ended September 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, electric generation fuel costs increased $1.2 million related to higher generation at Colstrip generating facilities of 82,741 MWhs and the price paid for fuel at the facility totaling $4.2 million offset by overall lower cost of gas for combustion turbine units due to lower generation and cost of gas at those facilities totaling $3.0 million.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with BPA increased $2.9 million for the nine months ended September 30, 2005 compared to the same periods in 2004. The overall increase for the nine months ended September 30, 2004 was a result of increased residential and small farm customer electric load. The residential exchange credit is a pass-through tariff item with a corresponding credit in electric operating revenue, thus it has no impact on electric margin or net income.

Purchased gas expenses increased $14.6 million and $88.3 million for the three and nine months ended September 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 September 30, 2005 and December 31, 2004 was $37.5 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 for the nine months ended September 30, 2005 include a one-time true-up of $3.3 million to reflect the impact of the demand charge. This adjustment impacts the comparability of gas margin information and purchased gas expense for the nine months ended September 30, 2005 compared with the same periods in 2004.

Unrealized gain on derivative instruments increased $1.4 million and decreased $1.4 million for the three and nine months ended September 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 $14.5 million and $26.2 million for the three and nine months ended September 30, 2005, respectively, compared to the same periods in 2004. Included in the increases for the three and nine months ended September 30, 2005 are a $1.3 million and a $4.5 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 nine months ended September 30, 2005 was an increase of $13.2 million and $21.7 million, respectively. The increase for the three months ended September 30, 2005 includes increases related to higher planned maintenance costs at PSE-owned energy production facilities, delivery infrastructure, and employee pension and benefit costs.

The increase for the nine months ended September 30, 2005 includes increases related to higher planned maintenance costs for PSE-owned energy production facilities, delivery facilities, employee pension and benefit costs. Production operation and maintenance increase for the nine months ended September 30, 2005 also includes 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 recorded in the second quarter 2005 - see further discussion under the section titled "Other." These increases were partially offset by lower storm damage repair costs of $7.2 million for nine months ended September 30, 2005 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 $3.0 million and $8.3 million for the three and nine months ended September 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 and 2005, including $32.8 million for the Everett Delta gas transmission line late in 2004. The nine months ended September 30, 2005 includes the effects of the $80.8 million Frederickson 1 generating facility in April 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 $2.1 million and $15.5 million for the three and nine months ended September 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. The increase for the three months ended September 30, 2005 was offset by a decrease of $1.5 million related to the 2005 property tax assessment issued by the Washington State Department of Revenue in the third quarter 2005.

Income taxes decreased $4.5 million and increased $14.5 million for the three and nine months ended September 30, 2005, respectively, compared to the same periods in 2004. The decrease for the three months ended September 30, 2005 was the result of lower taxable income as compared to the same period in 2004. The increase for the nine months ended September 30, 2005 is a result of higher taxable income and a higher effective federal income tax rate as compared to the same period in 2004.

OTHER INCOME AND INTEREST CHARGES

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

(DOLLARS IN MILLIONS) THREE MONTHS ENDED SEPTEMBER 30	2005	2004	CHANGE	PERCENT CHANGE
Interest charges	$ 43.0	$ 41.1	$ 1.9	4.6%

Interest charges increased $1.9 million for the three months ended September 30, 2005 compared to the same period in 2004. The three months ended September 30, 2005 increase is due primarily to higher amounts of short-term borrowings and the issuance of $250 million long-term senior notes in June 2005 at 5.483% which was used in part to repay a $200 million variable rate note with a lower interest rate offset by redemptions of $50.2 million of long-term debt with rates ranging from 6.45% to 7.70% in 2004. In addition, the increase was offset by a May 2005 redemption of $42.5 million of 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 table below sets forth significant changes in other income for PSE and its subsidiaries for the nine months ended September 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) NINE MONTHS ENDED SEPTEMBER 30	2005	2004	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 4.2	$ 2.0	$ 2.2	110.0 %

Other income increased $2.2 million (after-tax) for the nine months ended September 30, 2005 compared to the same period in 2004 primarily due to increases in the equity portion of allowance for funds used during construction and in the surrender value of corporate-owned life insurance policies.

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 into its regulated utility subsidiary, PSE. Management believes the 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 in 2005. Puget Energy is actively marketing InfrastruX and has held discussions with interested financial and strategic parties in 2005. Puget Energy has recently retained an investment banker to assist in the disposal of InfrastruX. To date, Puget Energy has not entered into a definitive agreement that would result in the sale of its investment in InfrastruX.

For the three and nine months ended September 30, 2005, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest) of $0.0 million and $0.9 million, respectively, compared to income of $1.7 million and $4.2 million (net of taxes and minority interest) for the three and nine months ended September 30, 2004, respectively. Included in the income for discontinued operations is a charge of $8.1 million after-tax for the three months ended September 30, 2005 and $14.3 million after-tax for the nine months ended September 30, 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. The following chart summarizes Puget Energy's income from discontinued operations for the three and nine months ended September 30, 2005:

(DOLLARS IN MILLIONS)	THREE MONTHS ENDED SEPTEMBER 30, 2005	NINE MONTHS ENDED SEPTEMBER 30, 2005
Net income reported by InfrastruX	$ 5.3	$ 7.8
InfrastruX depreciation and amortization not recorded by Puget Energy, net of tax	2.9	7.3
Puget Energy tax benefit from goodwill deduction	0.7	1.4
Puget Energy carrying value adjustment of InfrastruX, including cost of sale, net of tax	(8.1)	(14.3)
Minority interest in income from discontinued operations and other	(0.8)	(1.3)
Income from discontinued operations	$ --	$ 0.9

InfrastruX reported strong financial results and cash flow in the third quarter 2005. InfrastruX's operating revenue for the three and nine months ended September 30, 2005 was $111.7 million and $286.7 million, respectively, compared to $99.9 million and $267.5 million, respectively, for the same periods in 2004. Operating income for the three and nine months ended September 30, 2005 was $7.8 million and $14.3 million, respectively, compared to $3.6 million and $9.2 million, respectively, for the same periods in 2004. InfrastruX's bank and vendor debt under its credit agreements totaled $151.6 million at September 30, 2005 compared to $159.4 million at December 31, 2004 and $181.3 million at September 30, 2004. In May 2004, InfrastruX signed a three-year agreement with a group of banks to provide up to $150 million in financing. Under the credit agreement, Puget Energy is the guarantor of the line of credit. Certain InfrastruX subsidiaries also have borrowing capacities for working capital purposes of which Puget Energy is not the guarantor. Of the $150 million bank facility available to InfrastruX, $121 million was outstanding at September 30, 2005 and $131 million was outstanding at December 31, 2004.

In determining the fair value of its InfrastruX investment, Puget Energy has determined proceeds on a sale will first be used to extinguish all InfrastruX debt outstanding.

In accordance with SFAS No. 144, Puget Energy has adjusted the carrying value of its investment in InfrastruX to the estimate of fair value, less cost to sell, at September 30, 2005. This estimate could change based on InfrastruX financial performance and market conditions in the utility constructions services sector. After reflecting an $8.1 million carrying value reduction in the third quarter 2005 and $14.3 million for the nine months ended September 30, 2005, Puget Energy's equity investment in InfrastruX was $34.3 million at September 30, 2005.

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

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following are Puget Energy's and Puget Sound Energy's aggregate consolidated contractual obligations from continuing operations as of September 30, 2005:

Puget Energy and Puget Sound Energy		Payments Due Per Period			
Contractual Obligations (Dollars in Millions)	Total	2005	2006-2007	2008-2009	2010 & Thereafter
Long-term debt including interest	$ 3,867.7	$ 35.4	$ 470.8	$ 568.0	$ 2,793.5
Short-term debt	223.9	223.9	--	--	--
Junior subordinated debentures payable to a subsidiary trust [1]	910.7	10.1	39.8	39.8	821.0
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	176.6	16.0	49.3	57.0	54.3
Non-cancelable operating leases	125.8	3.5	33.1	27.6	61.6
Fredonia combustion turbines lease [2]	61.9	1.1	8.6	8.4	43.8
Energy purchase obligations	5,476.4	500.9	2,165.7	1,442.1	1,367.7
Financial hedge obligations	327.8	106.3	216.7	4.8	--
Pension funding[3]	44.5	3.1	8.2	9.8	23.4
Total contractual cash obligations	$ 11,217.2	$ 900.3	$ 2,992.2	$ 2,157.5	$ 5,167.2

Puget Energy. The following are Puget Energy's aggregate consolidated (including PSE) commercial commitments as of September 30, 2005:

Puget Energy COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	2005	2006-2007	2008-2009	2010 & THEREAFTER
		AMOUNT OF COMMITMENT EXPIRATION PER PERIOD			
Guarantees [4]	$ 121.0	$ --	$ 121.0	$ --	$ --
Liquidity facilities - available [5]	355.6	80.0	--	--	275.6
Energy operations letter of credit	0.5	--	0.5	--	--
Total commercial commitments	$ 477.1	$ 80.0	$ 121.5	$ --	$ 275.6

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, $121.0 was outstanding at June 30, 2005.*

5 *At September 30, 2005, PSE had available a $500 million unsecured credit agreement expiring in April 2010 and a $132 million receivables securitization facility expiring December 2005. At September 30, 2005, PSE had $70.0 million 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 $223.9 million and a letter of credit totaling $0.5 million, thereby effectively reducing the available borrowing capacity under these liquidity facilities to $337.6 million.*

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

Puget Sound Energy COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	2005	2006-2007	2008-2009	2010 & THEREAFTER
		AMOUNT OF COMMITMENT EXPIRATION PER PERIOD			
Liquidity facilities - available [1]	$ 355.6	$ 80.0	$ --	$ --	$ 275.6
Energy operations letter of credit	0.5	--	0.5	--	--
Total commercial commitments	$ 356.1	$ 80.0	$ 0.5	$ --	$ 275.6

1 *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 September 30, 2005, Rainier Receivables had $70.0 million sold under the receivables securitization facility, leaving $62.0 million of receivables available to be sold under the program. During the three months ended September 30, 2005 and 2004, Rainier Receivables sold a cumulative $130.0 million and $81.0 million of receivables, respectively. During the nine months ended September 30, 2005, and 2004, Rainier Receivables sold a cumulative $190.0 million and $348.0 million of receivables, respectively.

FREDONIA 3 AND 4 OPERATING LEASE

PSE leases two combustion turbines for its Fredonia 3 and 4 electric generating facility pursuant to a master operating lease that was amended 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 September 30, 2005, PSE's outstanding balance under the lease was $54.7 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 $400.7 million for the nine months ended September 30, 2005. Utility construction expenditures in 2005, 2006 and 2007 are anticipated to be the following:

CAPITAL EXPENDITURE PROJECTIONS (DOLLARS IN MILLIONS)	2005	2006	2007
Energy delivery, technology and facilities	$ 400	$ 445	$ 475
Hopkins Ridge wind project	190	--	--
Wild Horse wind project	80	300	--
Other new energy resources [1]	--	--	--
Total capital expenditures	$ 670	$ 745	$ 475

[1] *Construction expenditures for other new energy resources 2006 and 2007 have not been determined.*

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 a notice to proceed with construction on 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 in late 2005, the energy will be delivered to PSE's service territory by BPA's transmission system via an interconnection. PSE anticipates spending approximately $190 million on the project. Included in the $190 million estimate is the cost to acquire and construct the wind plant, to fund upgrades to the transmission systems of the Bonneville Power Administration and other regional transmission providers, and for development, transaction and financing costs.

On September 30, 2005, PSE completed the acquisition of the Wild Horse wind project in central Washington State from Horizon Wind Energy LLC and issued a notice to proceed with construction on the project. Simultaneously, PSE entered into an agreement with Vestas-American Wind Technology, Inc. (Vestas) to purchase and construct a total of 127 Vestas 1.8 MW wind turbines providing up to approximately 230 MW of capacity, or 73 average MW. The Wild Horse wind project is within PSE's service territory and upon completion in late 2006, the energy will connect to an existing PSE transmission line. PSE anticipates spending up to approximately $380 million on the project. Included in the $380 million estimate is the cost to acquire land, wind turbines and other necessary assets, construction costs, and transaction, financing and contingency costs. Through September 30, 2005, PSE had spent $27.5 million on the Wild Horse project.

CAPITAL RESOURCES

CASH FROM OPERATIONS

Cash generated from operations for the nine months ended September 30, 2005 was $301.0 million. During that period, $6.2 million was used for AFUDC, which reduced interest expense, and $65.9 million for payment of dividends. Consequently, cash flows available for utility construction expenditures and other capital expenditures were $228.9 million or 57% of the $400.7 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for the nine months ended September 30, 2005. For the nine months ended September 30, 2004, cash generated from operations was $282.1 million, $3.8 million was used for AFUDC, which reduced interest expense, and $65.1 million was used for payment of dividends. Therefore, cash flows available for utility construction expenditures and other capital expenditures were $213.2 million, or 66% of the $324.3 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for the nine month period ended September 30, 2004. The following table provides a summary of cash available and construction expenditures:

(DOLLARS IN MILLIONS)
(UNAUDITED)

For the nine months ended September 30	2005	2004
Cash from operations	$ 301.0	$ 282.1
Less: Dividends paid	(65.9)	(65.1)
AFUDC	(6.2)	(3.8)
Cash available for construction expenditures	$ 228.9	$ 213.2
Construction and energy efficiency expenditures	$ 417.1	$ 337.6
Less: AFUDC	(6.2)	(3.8)
Cash received from refundable customer contributions	(10.2)	(9.5)
Net construction and energy efficiency expenditures	$ 400.7	$ 324.3

The overall cash generated from operating activities for the nine month period ended September 30, 2005 increased $18.9 million compared to the same period in 2004. The increase in cash was primarily the result of an increase in the accounts payable balance of $40.1 million, as compared to 2004, an increase in cash collateral received from energy suppliers of $23.5 million, and a $11.7 million positive cash flow change in the Purchased Gas Adjustment Receivable. These increases were partially offset by a $39.2 million decrease in deferred income taxes, income tax credits, and taxes payable. The increase in cash was also offset by an increase of $17.2 million in prepayments.

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 September 30, 2005, PSE could issue:

- approximately $250 million of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $417 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 September 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 September 30, 2005;
- approximately $635 million of additional preferred stock at an assumed dividend rate of 6.625%; and
- approximately $325 million of unsecured long-term debt.

At September 30, 2005, PSE had approximately $3.7 billion in electric and gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

CREDIT RATINGS

Neither Puget Energy nor PSE has 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 borrowing costs and commitment fee increase as PSE's secured long-term debt ratings decline. A downgrade in commercial paper ratings could preclude PSE's ability to issue commercial paper under its current programs. The marketability of PSE commercial paper is currently limited by the A-3/P-2 ratings by Standard & Poor's and Moody's Investors Service. In addition, downgrades in any or a combination of PSE's debt ratings may prompt counterparties on a contract by contract basis in the wholesale electric, wholesale gas and financial derivative markets to require PSE to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other mutually agreeable security.

The ratings of Puget Energy and PSE, as of October 21, 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.

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

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

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

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

On October 26, 2005, Puget Energy agreed to sell 15 million shares of common stock to Lehman Brothers Inc. The net proceeds of approximately $309.8 million were invested in PSE and used to repay short-term debt incurred to primarily fund PSE's construction program. In addition, Lehman Brothers has a 30 day option to purchase up to an additional 1.7 million shares of Puget Energy common stock if the underwriter sells more than 15 million shares in the offering.

Based on PSE's goal to become a more vertically integrated utility, it is expected that further issuances of debt 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 extended the expiration date from June 2007 to April 2010. Under the terms of the credit agreement, PSE pays a floating interest rate on outstanding borrowings based either on the agent bank's prime rate or on LIBOR plus a marginal rate based on PSE's long-term credit rating at the time of borrowing. PSE pays a commitment fee on any unused portion of the credit agreement also based on long-term credit ratings of PSE. PSE also had available $132 million of its $150 million receivables securitization program with Rainier Receivables, which expires in December 2005. At September 30, 2005, PSE had available $500 million in the unsecured credit agreement and $62 million under its receivables securitization facility, both of which provide credit support for outstanding commercial paper and letters of credit. At September 30, 2005, there was $70 million in receivables securitization facility outstanding, $223.9 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 $337.6 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 September 30, 2005, there were no amounts outstanding under this credit agreement.

On September 29, 2005, Puget Energy paid off a $5 million outstanding balance on a bank credit agreement and closed the credit agreement.

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 $3.6 million (159,985 shares) and $10.9 million (480,005 shares) for the three and nine months ended September 30, 2005, respectively, compared to $3.8 million (176,227 shares) and $11.6 million (530,430 shares) for the three and nine months ended September 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. The two petitions have been consolidated and briefing is expected to be completed in the first quarter 2006.

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 denied PSE’s shoreline exemption application. 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 were held in September 2005 and, on October 5, 2005, PSE’s appeal was granted. Skagit County sought reconsideration of the decision, which was denied. On October 21, 2005, an appeal to the Skagit County Board of Commissioners was filed by Skagit County Dike District Nos. 1, 12 and 17, City of Mount Vernon and City of Bellingham. 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 fourth quarter 2005. 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

Power Cost Only Rate Case. On October 20, 2005, the Washington Commission approved a 3.7%, or $55.6 million annually, power cost only rate case (PCORC) increase to allow PSE to recover higher projected costs of power effective November 1, 2005. Included in the increase is the recovery of capital and operating costs of the newly acquired Hopkins Ridge wind project, which is expected to be completed in late 2005. The Washington Commission also approved an amendment to the

PCA mechanism by changing the annual PCA reporting periods to a calendar year period beginning January 1, 2007 with provisions made to reduce the sharing bands in half for the period July 1, 2006 through December 31, 2006. The order also requires PSE to update the power cost baseline rate in the PCA mechanism by filing a tariff change to the power cost rate during May 2006 which would be effective July 1, 2006. Finally, the order requires PSE to file a general rate case by mid-February 2006 so that a new power cost baseline rate will be effective on January 1, 2007.

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]	233	283	305	362	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[1]	Customers' Share	Company's Share [2]
+/- $20 million	0%	100%
+/- $20 - $40 million	50%	50%
+/- $40 - $120 million	90%	10%
+/- $120 million	95%	5%

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

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

Based on past activity under the PCA mechanism and volatility of power costs, it is possible that PSE could experience higher expenses associated with excess power based on the sharing arrangement once the cumulative $40 million cap expires on June 30, 2006. As such, the risk dynamics change for PSE and its customers. On October 20, 2005, the Washington Commission approved an amendment to the PCA mechanism changing the PCA period to a calendar year beginning January 1, 2007, keeping the graduated scale but not capping the excess power costs. The Washington Commission also made provision to reduce the graduated scale to half the annual excess power costs for the period July 1, 2006 through December 31, 2006 without a cap on excess power costs.

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 September 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 *	$ 65.5	$ 264.3	$ 252.0	$ 245.5	$ 231.3	$ 216.6	$ 205.2
Projected Tenaska benchmark costs	44.0	175.3	174.8	182.9	189.9	197.4	205.6
Over (under) benchmark costs	$ 21.5	$ 89.0	$ 77.2	$ 62.6	$ 41.4	$ 19.2	$ (0.4)
Projected 50% disallowance based on Washington Commission methodology	$ 2.3	$ 8.8	$ 7.7	$ 6.3	$ 4.7	$ 3.0	$ --

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

GAS REGULATION AND RATES

On September 28, 2005, the Washington Commission approved PSE's request for a Purchased Gas Adjustment (PGA) filed on August 29, 2005. The approved request will increase rates and revenues by approximately 14.7% or $121.6 million annually. The increase in PGA rates was to recover higher market prices of natural gas sold to customers. The PGA mechanism passes through to customers increases or decreases in the gas supply portion of the natural gas service rates based upon changes in gas prices. PSE's gas margin and net income are not affected by the change in PGA rates.

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.

On October 18, 2005, PSE learned of two additional potential royalty claims that are likely to be asserted by the State of Montana in the near future. The potential claims, in total, amount to $0.3 million plus interest. PSE's initial assessment of these claims is that they would likely have a similar ultimate result to the parallel MMS claims that are being appealed. If the State of Montana's claims are asserted, PSE will defend them consistently with the MMS claims. PSE reserved $1.1 million for the MMS claim in the second quarter 2004.

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. The NOPA states that the deduction is not valid for the 2003 tax year, and requests payment of approximately $14.5 million in tax. . Management of Puget Energy believes the deduction is valid and intends to vigorously defend the deduction, however the outcome of this issue cannot be predicted. Any potential tax related payment (excluding interest) would have no impact on earnings as it would be recognized as a deferred tax asset. If the Company is unsuccessful, a charge for interest expense could apply.

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

Due to new Regulations, PSE has filed on October 19, 2005 an accounting order with the Washington Commission to defer cost using PSE's allowed net of tax rate of return of 7.01% associated with increasing capital borrowing necessary to repay $72 million in income taxes that was treated as a reduction to rate base in the Washington Commission order of February 18, 2005, beginning November 1, 2005. This accounting petition was approved by the Washington Commission on October 26, 2005, for deferral of additional capital costs beginning November 1, 2005. PSE will request recovery of this deferral commencing January 2007 in its February 2006 electric general rate case filing.

Energy Policy Act of 2005. The recent adoption of the Energy Policy Act of 2005 includes a number of features that will directly or indirectly impact the Company. The Energy Policy Act of 2005 promotes infrastructure reliability and investment, including diverse energy supplies through cost recovery mechanisms for reliable investments, acceleration of depreciation and production tax credits for certain types of generating facilities. As a result, PSE will receive production tax credits related to its wind generating facilities currently under construction, which will be passed onto customers through lower rates. The Energy Policy Act also promotes energy efficiency and conservation through tax incentives, which will benefit PSE's energy efficiency programs. In addition, the Energy Policy Act repealed the Public Utility Holding Company Act of 1935 and made enhancements of consumer and market protections, including reform of Public Utility Regulatory Policy Act (PURPA) and a prohibition on conversion of Northwest firm transmission rights. All the effects of the Energy Policy Act on the Company are not known at this time.

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 quarters ended March 31, 2005 and June 30, 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 and an August 8, 2005 order for submitting cost recovery 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, Enron, Reliant and Public Service Company of Colorado. These settlements, supported by a statement from FERC chairman Joseph Kelliher, may suggest that the process momentum toward settlement in the California Refund Proceedings is increasing.

2. **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. On March 10, 2005, Wah Chang filed a notice of appeal to the United States Court of Appeals for the Ninth Circuit. Wah Chang filed its opening brief on September 21, 2005. Response briefs are due November 30, 2005 and the appeal has been consolidated with Wah Chang's complaint against energy marketers.

3. **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 sought, among other things, restitution of all funds acquired by means that violate the law and payment of treble damages, interest and penalties. The cross-complaints asserted essentially that the cross-defendants, including PSE, were also participants in the California energy market at relevant times, and that any remedies ordered against some market participants should be ordered against all. Reliant and Duke also sought indemnification, declaratory relief and conditional relief as buyers in transactions involving cross-defendants should the plaintiffs prevail. On June 3, 2005, the cross-defendants,

including PSE, filed a demurrer seeking to dismiss the cross-complaints, the hearing on which is set for December 23, 2005.

On July 22, 2005, the court considered a proposed settlement that would resolve all claims against the Duke parties and indicated a "preliminary approval" setting a hearing date for final approval of December 9, 2005. In August, Reliant also announced it had reached a settlement that would result in the dismissal of the Master Complaint. No date has yet been set for approval of the Reliant Settlement.

The defendants, including Duke and Reliant, also filed demurrers on the Master Complaint, which were preliminarily sustained by the court in an order dated October 4, 2005, based on federal preemption principles and the filed rate doctrine. The order sustaining the demurrers acknowledges that the demurrers were removed from the calendar pending approval of the proposed settlements. The Court set a status conference for November 10, 2005 to discuss the remaining issues in the cross-complaints.

4. **California Receivable.** At September 30, 2005, PSE had a net receivable totaling $21.3 million in connection with wholesale sales in 2000 to the California Independent System Operator (CAISO) and counterparties where payment to PSE was conditioned on the counterparties being paid by the California Power Exchange. In August 2005, PSE submitted a Fuel Cost Adjustment Claim for $3.4 million related to sales in 2000 to the CAISO, pursuant to FERC's California refund proceeding.

   Pursuant to an order issued by FERC in August 2005, PSE also submitted a Portfolio Cost Claim in September 2005 for $9.3 million to the CAISO. FERC has not yet clarified several important computational issues with these types of claims, nor has it determined a mechanism for the allocation and payment of Portfolio Cost Claim and Fuel Cost Adjustment Claim. PSE's ability to recover all or a portion of these claims is uncertain at the present time.

   Based upon FERC orders, PSE has determined a range related to its CAISO receivable to be between $21.3 million (PSE's net receivable balance) and $34.2 million including interest on its past due receivables as of September 30, 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. For the period July 1, 2006 through December 31, 2006 the sharing bands will be half of the annual bands without a cap for excess power costs and beginning January 1, 2007 the PCA mechanism will provide sharing of costs and benefits that are graduated over four levels for each calendar year without a maximum cap for excess power costs.

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

The nature of serving regulated electric customers with its 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 realizing speculative trading revenues. Therefore wholesale market transactions are focused on balancing the Company's energy portfolio, reducing costs and risks where feasible, and reducing volatility in wholesale costs and margin in the portfolio. In order to manage risks effectively, the Company enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and 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 energy portfolios. 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 Energy 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 advisable 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 September 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 independent third parties. 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 September 30, 2005, the Company had a net asset of approximately $89.8 million of energy contracts designated as qualifying cash flow hedges and a corresponding unrealized gain of $58.4 million after-tax recorded in other comprehensive income. These cash flow hedges represent forward financial purchases of gas intended to run PSE-owned electric plants in future periods. If it is determined that it is uneconomical to run the plants in the future period, the hedging relationship is ended and the cash flow hedge is de-designated and any unrealized gains and losses are recorded in the income statement. Gains and losses, when these de-designated cash flow hedges are settled, are recognized in energy costs and are included as part of the PCA mechanism. Of the amount in other comprehensive income, 99% of the mark-to-market gain beginning October 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 loss of $0.3 million through current earnings for the three months ended September 30, 2005 and at a loss of $0.3 million for the nine months ended September 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 October 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 September 30, 2005, the Company also has a net asset of approximately $125.9 million related to the fair value of gas contracts to serve gas customers. The third quarter 2005 saw market gas prices spike in part due to hurricanes affecting supply, therefore existing gas financial hedges showed sizeable gains when marked to the higher market prices. All mark-to-market adjustments relating to the natural gas business have been reclassified to a deferred account in accordance with SFAS No. 71 due to the PGA mechanism. The PGA mechanism passes on to customers increases and decreases in the cost of natural gas supply. As the gains and losses on the cash flow hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism. A hypothetical 10% 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 $11.1 million after-tax and would increase current earnings for those contracts marked-to-market in earnings by $1.4 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 September 30, 2005, the unrealized loss associated with the two swap contracts was $0.5 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 $9.5 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

September 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 September 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 September 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 September 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. <u>Legal Proceedings</u>

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 September 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 6. <u>Exhibits</u>

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: November 1, 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 September 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 September 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.