

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

FORM 10-Q

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

For the quarterly period ended March 31, 2009

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

1-4393

PUGET SOUND ENERGY, INC.

91-0374630

A Washington Corporation
10885 NE 4th Street, Suite 1200
Bellevue, Washington 98004-5591
(425) 454-6363

Indicate by check mark whether the registrant: (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes /X/ No / /

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes / / No / /

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer, accelerated filer and smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	/ /	Accelerated filer	/ /	Non-accelerated filer	/X/	Smaller reporting company	/ /
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Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act)

Yes / / No /X/

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

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
ASC	Average System Cost
BPA	Bonneville Power Administration
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
ISDA	International Swaps and Derivatives Association
kW	Kilowatt
kWh	Kilowatt Hour
LIBOR	London Interbank Offered Rate
MMBtus	One Million British Thermal Units
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NPNS	Normal Purchase Normal Sale
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PF	BPA Priority Firm Exchange Rate
PGA	Purchased Gas Adjustment
PSE	Puget Sound Energy, Inc.
Puget Energy	Puget Energy, Inc.
Puget Holdings	Puget Holdings LLC
PURPA	Public Utility Regulatory Policy Act
REP	Residential Exchange Program
RPSA	Residential Purchase and Sale Agreement
SFAS	Statement of Financial Accounting Standards
VIE	Variable Interest Entity
Washington Commission	Washington Utilities and Transportation Commission
WSPP	Western Systems Power Pool

FORWARD-LOOKING STATEMENTS

Puget Sound Energy, Inc. (PSE) is 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 PSE. This report includes forward-looking statements, which are statements of expectations, beliefs, plans, objectives and assumptions of future events or performance. Words or phrases such as “anticipates,” “believes,” “estimates,” “expects,” “future,” “intends,” “plans,” “predicts,” “projects,” “will likely result,” “will continue” or similar expressions identify forward-looking statements.

Forward-looking statements involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PSE’s expectations, beliefs and projections are expressed in good faith and are believed by 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. However, there can be no assurance that 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 PSE to differ materially from those discussed in forward-looking statements include:

- Governmental policies and regulatory actions, including those of the Federal Energy Regulatory Commission (FERC) and the Washington Utilities and Transportation Commission (Washington Commission), with respect to allowed rates of return, cost recovery, financing, 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, maintenance, construction and operation of natural gas and electric distribution and transmission facilities (natural gas and electric), licensing of hydroelectric operations and natural gas storage facilities, recovery of other capital investments, recovery of power and natural gas costs, recovery of regulatory assets and present or prospective wholesale and retail competition;
- Failure to comply with FERC or Washington Commission standards and/or rules, which could result in penalties based on the discretion of either commission;
- Failure to comply with electric reliability standards developed by the North American Electric Reliability Corporation (NERC) for users, owners and operators of the power system, which could result in penalties of up to \$1.0 million per day per violation;
- Changes in, adoption of, and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, emissions, natural resources and fish and wildlife (including the Endangered Species Act);
- The ability to recover costs arising from changes in enacted federal, state or local tax laws through revenue in a timely manner;
- Changes in tax law, related regulations, or differing interpretation or enforcement of applicable law by the Internal Revenue Service or other taxing jurisdiction;
- Natural disasters, such as hurricanes, windstorms, earthquakes, floods, fires and landslides, which can interrupt service and/or cause temporary supply disruptions and/or price spikes in the cost of fuel and raw materials and impose extraordinary costs;
- Commodity price risks associated with procuring natural gas and power in wholesale markets;
- Wholesale market disruption, which may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, negatively affect wholesale energy prices and/or impede PSE’s ability to manage its energy portfolio risks and procure energy supply, affect the availability and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- Financial difficulties of other energy companies and related events, which may affect the regulatory and legislative process in unpredictable ways and also adversely affect the availability of and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- The effect of wholesale market structures (including, but not limited to, regional market designs or transmission organizations) or other related federal initiatives;
- PSE electric or natural gas distribution system failure, which may impact PSE’s ability to deliver energy supply to its customers;
- Changes in weather conditions in the Pacific Northwest, which could have effects on customer usage and PSE’s revenues;
- Weather, which can have a potentially serious impact on PSE’s ability to procure adequate supplies of natural gas, fuel or purchased power to serve its customers and on the cost of procuring such supplies;
- Variable hydro conditions, which can impact streamflow and PSE’s ability to generate electricity from hydroelectric facilities;

- Plant outages, which can have an adverse impact on PSE's expenses with respect to repair costs, added costs to replace energy or higher costs associated with dispatching a more expensive resource;
- The ability of natural gas or electric plant to operate as intended;
- The ability to renew contracts for electric and natural gas supply and the price of renewal;
- Blackouts or large curtailments of transmission systems, whether PSE's or others', which can affect PSE's ability to deliver power or natural gas to its customers and generating facilities;
- The ability to restart generation following a regional transmission disruption;
- The failure of the interstate natural gas pipeline delivering to PSE's system, which may impact PSE's ability to adequately deliver natural gas supply or electric power to its customers;
- The amount of collection, if any, of PSE's receivables from the California Independent System Operator (CAISO) and other parties and the amount of refunds found to be due from PSE to the CAISO or other parties;
- Industrial, commercial and residential growth and demographic patterns in the service territories of PSE;
- General economic conditions in the Pacific Northwest, which might impact customer consumption or affect PSE's accounts receivable;
- The loss of significant customers or changes in the business of significant customers or the condemnation of PSE's facilities, which may result in changes in demand for PSE's services;
- The failure of information systems or the failure to secure information system data which may impact the operations and cost of PSE's customer service, generation, distribution and transmission;
- The impact of acts of God, terrorism, flu pandemic or similar significant events;
- Capital market conditions, including changes in the availability of capital and interest rate fluctuations;
- Employee workforce factors, including strikes, work stoppages, availability of qualified employees or the loss of a key executive;
- The ability to obtain insurance coverage and the cost of such insurance;
- The ability to maintain effective internal controls over financial reporting and operational processes;
- Changes in PSE's credit ratings, which may have an adverse impact on the availability and cost of capital for PSE; and
- Deteriorating values of the equity, fixed income and other markets which could significantly impact the value of investments of PSE's retirement plan and post-retirement medical trusts and the funding of obligations thereunder.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PSE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. You are also advised to consult Item 1A-"Risk Factors" in the Company's most recent annual report on Form 10-K.

PART I FINANCIAL INFORMATIONItem 1. **Financial Statements**

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

	THREE MONTHS ENDED MARCH 31,	
	2009	2008
Operating revenues:		
Electric	\$ 600,230	\$ 606,134
Gas	506,436	443,236
Other	889	1,562
Total operating revenues	1,107,555	1,050,932
Operating expenses:		
Energy costs:		
Purchased electricity	260,249	272,832
Electric generation fuel	48,127	47,014
Residential exchange	(32,404)	(7)
Purchased gas	320,063	276,195
Net unrealized gain on derivative instruments	2,330	88
Utility operations and maintenance	114,893	112,163
Non-utility expense and other	1,307	55
Merger and related costs	27,563	--
Depreciation and amortization	81,361	75,367
Conservation amortization	20,829	13,366
Taxes other than income taxes	101,343	94,273
Total operating expenses	945,661	891,346
Operating income	161,894	159,586
Other income (deductions):		
Other income	9,932	6,814
Other expense	(2,443)	(975)
Interest charges:		
AFUDC	1,681	2,429
Interest expense	(52,576)	(51,048)
Interest expense on Puget Energy note	(73)	(237)
Income before income taxes	118,415	116,569
Income tax expense	33,438	35,665
Net income	\$ 84,977	\$ 80,904

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 MARCH 31,	
	2009	2008
Net income	\$ 84,977	\$ 80,904
Other comprehensive income:		
Unrealized gain from pension and postretirement plans, net of tax of \$509 and \$95, respectively	945	176
Net unrealized gain (loss) on energy derivative instruments during the period, net of tax of \$(36,911) and \$25,457, respectively	(68,549)	47,277
Reclassification of net unrealized gain on energy derivative instruments settled during the period, net of tax of \$7,521 and \$957, respectively	13,967	1,778
Amortization of financing cash flow hedge contracts to earnings, net of tax of \$43 and \$43, respectively	80	80
Other comprehensive income (loss)	(53,557)	49,311
Comprehensive income	\$ 31,420	\$ 130,215

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

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

ASSETS

	MARCH 31, 2009 (Unaudited)	DECEMBER 31, 2008
Utility plant: (at original cost, including construction work in progress of \$282,785 and \$255,214, respectively)		
Electric plant	\$ 6,702,507	\$ 6,596,359
Gas plant	2,546,179	2,500,236
Common plant	572,155	550,368
Less: Accumulated depreciation and amortization	(3,445,778)	(3,358,816)
Net utility plant	6,375,063	6,288,147
Other property and investments:		
Investment in Bonneville Exchange Power contract	29,095	29,976
Other property and investments	117,946	118,039
Total other property and investments	147,041	148,015
Current assets:		
Cash	101,028	38,470
Restricted cash	15,988	18,889
Accounts receivable, net of allowance for doubtful accounts	395,871	207,776
Secured pledged accounts receivable	--	158,000
Unbilled revenues	171,604	248,649
Materials and supplies, at average cost	66,718	62,024
Fuel and gas inventory, at average cost	73,266	120,205
Unrealized gain on derivative instruments	22,186	15,618
Prepaid income taxes	10,272	17,317
Prepaid expenses and other	24,285	14,420
Deferred income taxes	34,508	9,439
Total current assets	915,726	910,807
Other long-term and regulatory assets:		
Regulatory asset for deferred income taxes	92,202	95,417
Regulatory asset for PURPA buyout costs	102,669	110,838
Power cost adjustment mechanism	3,147	3,126
Other regulatory assets	765,715	766,732
Unrealized gain on derivative instruments	10,203	6,712
Other	73,071	40,365
Total other long-term and regulatory assets	1,047,007	1,023,190
Total assets	\$ 8,484,837	\$ 8,370,159

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

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

CAPITALIZATION AND LIABILITIES

	MARCH 31, 2009 (Unaudited)	DECEMBER 31, 2008
Capitalization:		
Common shareholder's investment:		
Common stock (\$10 stated value) - 150,000,000 shares authorized, 85,903,791 shares outstanding	\$ --	\$ 859,038
Common stock (\$0.01 par value) - 150,000,000 shares authorized, 85,903,791 shares outstanding	859	--
Additional paid-in capital	2,962,864	1,296,005
Earnings reinvested in the business	351,501	356,947
Accumulated other comprehensive loss, net of tax	(316,361)	(262,804)
Total shareholder's equity	2,998,863	2,249,186
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	--	1,889
Junior subordinated notes	250,000	250,000
Long-term debt	2,295,860	2,270,860
Total redeemable securities and long-term debt	2,545,860	2,522,749
Total capitalization	5,544,723	4,771,935
Current liabilities:		
Accounts payable	225,142	341,255
Short-term debt	175,000	964,700
Short-term note owed to parent	19,443	26,053
Current maturities of long-term debt	233,000	158,000
Accrued expenses:		
Purchased gas liability	29,725	8,892
Taxes	96,172	85,068
Salaries and wages	19,374	35,280
Interest	46,084	36,112
Unrealized loss on derivative instruments	324,331	236,866
Other	141,999	117,223
Total current liabilities	1,310,270	2,009,449
Long-term liabilities and regulatory liabilities:		
Deferred income taxes	769,863	750,440
Unrealized loss on derivative instruments	176,665	158,423
Regulatory liabilities	222,181	219,221
Other deferred credits	461,135	460,691
Total long-term liabilities and regulatory liabilities	1,629,844	1,588,775
Total capitalization and liabilities	\$ 8,484,837	\$ 8,370,159

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

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(Dollars in thousands)
(Unaudited)

FOR QUARTER ENDED MARCH 31, 2009	COMMON STOCK		ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE LOSS	TOTAL AMOUNT
	SHARES	AMOUNT				
Balance at December 31, 2008	85,903,791	\$ 859,038	\$ 1,296,005	\$ 356,947	\$ (262,804)	\$ 2,249,186
Net income	--	--	--	84,977	--	84,977
Common stock dividend declared	--	--	--	(90,423)	--	(90,420)
Change in par value	--	(858,179)	858,179	--	--	--
Investment from Puget Energy	--	--	808,680	--	--	808,677
Other comprehensive loss	--	--	--	--	(53,557)	(53,557)
Balance at March 31, 2009	85,903,791	\$ 859	\$ 2,962,864	\$ 351,501	\$ (316,361)	\$ 2,998,863

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

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

	THREE MONTHS ENDED MARCH 31,	
	2009	2008
Operating activities:		
Net income	\$ 84,977	\$ 80,904
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	81,361	75,367
Conservation amortization	20,829	13,366
Deferred income taxes and tax credits, net	26,408	22,327
Amortization of gas pipeline capacity assignment	(2,308)	(2,614)
Non cash return on regulatory assets	(2,397)	(3,363)
Net unrealized loss on derivative instruments	2,330	88
Mint Farm deferred costs	(5,449)	--
Non cash Colstrip settlement	--	10,487
Change in residential exchange program	6,330	(921)
Other	(16,630)	(251)
Counterparty collateral deposit	(5,268)	--
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	46,949	25,456
Materials and supplies	(4,693)	930
Fuel and gas inventory	46,938	59,482
Prepaid income taxes	7,046	41,271
Prepayments and other	(9,865)	3,146
Purchased gas receivable/payable	20,833	(9,436)
Accounts payable	(101,670)	(17,884)
Taxes payable	11,530	22,900
Accrued expenses and other	6,654	11,397
Net cash provided by operating activities	213,905	332,652
Investing activities:		
Construction expenditures - excluding equity AFUDC	(179,308)	(126,646)
Energy efficiency expenditures	(16,570)	(14,010)
Restricted cash	2,901	(1)
Other	4,960	1,884
Net cash used by investing activities	(188,017)	(138,773)
Financing activities:		
Change in short-term debt, net	(10,376)	(158,882)
Dividends paid	(67,871)	(48,581)
Loan from (payment to) parent	(6,610)	14,234
Long term bond issued	250,000	--
Redemption of trust preferred stock	(1,889)	--
Redemption of bonds and notes	(150,000)	--
Investment from parent	29,616	--
Issuance cost of bonds and other	(6,199)	3,979
Net cash provided (used) by financing activities	36,671	(189,250)
Net increase in cash	62,559	4,629
Cash at beginning of year	38,470	40,773
Cash at end of period	\$ 101,029	\$ 45,402
Supplemental cash flow information:		
Cash payments for interest (net of capitalized interest)	\$ 39,709	\$ 38,642
Cash refunds from income taxes	(271)	(39,730)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Consolidation Policy

BASIS OF PRESENTATION

Puget Sound Energy, Inc. (PSE) is a subsidiary of Puget Energy, Inc. (Puget Energy), an energy services holding company incorporated in the state of Washington in 1999. On February 6, 2009, Puget Holdings LLC (Puget Holdings) completed its merger with Puget Energy. PSE's basis of accounting will continue to be on a historical basis and PSE's financial statements will not include any Statement of Financial Accounting Standards (SFAS) No. 141R, "Business Combinations" purchase accounting adjustments.

PSE's consolidated financial statements include the accounts of PSE and its subsidiaries. PSE is referred to herein as "the Company." The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. The consolidated financial statements contained in this Form 10-Q are unaudited. In the opinion of PSE's management, 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 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 Report on Form 10-K for the year ended December 31, 2008.

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) 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.

PSE collected Washington State excise taxes (which are a component of general retail rates) and municipal taxes of \$85.9 million for the three months ended March 31, 2009 and \$76.6 million for the three months ended March 31, 2008. The Company's policy is to report such taxes on a gross basis in operating revenues and taxes other than income taxes in the accompanying consolidated statements of income.

(2) Merger

In conjunction with the merger on February 6, 2009, Puget Energy contributed \$808.9 million in capital to PSE, of which \$779.3 million was used to pay off short-term debt owed by PSE, including \$188.0 million in short-term debt outstanding through the PSE Funding accounts receivable securitization program that was terminated upon closing of the merger. The \$779.3 million is excluded as cash provided by financing activities in the statement of cash flows. An additional \$29.6 million of the capital contribution was used to pay for change in control costs associated with the merger and is included as cash provided by financing activities in the statement of cash flows. The stated value of the outstanding common stock was changed from \$10.00 to a par value of \$0.01 per share. The remaining \$9.99 of the original stated value was transferred to additional paid in capital.

During the first quarter 2009, PSE incurred \$27.6 million pre-tax in merger costs. These costs include compensation costs as a result of the change in control, write-off of deferred debt costs associated with the termination of the pre-merger credit facilities, expenses associated with new credit facilities and the impact of deferred compensation liabilities as a result of the merger. Pursuant to the Washington Commission merger order commitments, PSE will not seek recovery of these costs. In addition, a requirement of the merger was that Puget Energy be the sole shareholder of PSE. Accordingly, on February 5, 2009, prior to the close of the merger, PSE defeased and called for the redemption of its two outstanding series of preferred stock. The redemption was completed on March 13, 2009.

The merger order issued by the Washington Utilities and Transportation Commission (Washington Commission) was subject to a Settlement Stipulation which included 78 conditions. The conditions provided for, among other matters, minimum equity to capitalization ratio, dividend restrictions, financial reporting and rate credits of \$10.0 million per year for ten years.

(3) Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” (SFAS No. 133), as amended, requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. The Company enters into contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts, option contracts and swaps. The majority of the Company’s physical contracts qualify for the Normal Purchase Normal Sale (NPNS) exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies to contracts with creditworthy counterparties, for which physical delivery is probable and in quantities that will be used in the normal course of business. Power purchases designated as NPNS must meet additional criteria if the counterparty owns or controls energy resources within the western region to allow for physical delivery of the energy and if the transaction is within the Company’s forecasted load requirements. The Company may enter into financial fixed contracts to hedge the variability of certain NPNS contracts. Those contracts that do not meet NPNS exception or cash flow hedge criteria are marked-to-market to current earnings in the income statement, subject to deferral under SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation” (SFAS No. 71), for energy related derivatives due to the Power Cost Adjustment (PCA) mechanism and Purchased Gas Adjustment (PGA) mechanism.

The Company pursues various portfolio optimization strategies, but is not in the business of assuming risk for the purpose of realizing speculative trading revenues. The nature of serving regulated electric customers with its wholesale portfolio of owned and contracted electric generation resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. 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. The Company’s energy risk portfolio management function monitors and manages these risks using analytical models and tools. 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 following table presents electric derivatives that do not meet the NPNS exception at March 31, 2009 and December 31, 2008, including contracts designated as cash flow hedges:

(DOLLARS IN MILLIONS)	ELECTRIC DERIVATIVES	
	MARCH 31, 2009	DECEMBER 31, 2008
Current asset	\$ 1.3	\$ 0.4
Long-term asset	0.9	0.5
Total assets	\$ 2.2	\$ 0.9
Current liability	\$ 151.9	\$ 90.6
Long-term liability	122.3	96.1
Total liabilities	\$ 274.2	\$ 186.7

If it is determined that it is uneconomical to operate the Company’s controlled electric generating facilities in the future period, the fuel supply cash flow hedge relationship is terminated and the hedge is de-designated which results in recognition of future changes in value in the income statements. As these contracts are settled, amounts previously deferred in other comprehensive income (OCI) are recognized as energy costs and are included as part of the PCA mechanism.

The following table presents the impact of changes in the market value of derivative instruments not meeting NPNS or cash flow hedge criteria to the Company’s earnings during the three months ended March 31, 2009 and March 31, 2008:

(DOLLARS IN MILLIONS)	MARCH 31, 2009	MARCH 31, 2008	CHANGE
Decrease in earnings	\$ (2.3)	\$ (0.1)	\$ (2.2)

The decrease in earnings in 2009 primarily relates to a \$3.2 million unrealized loss associated with the ineffective portion of cash flow hedges for two long-term power supply agreements.

The amount of unrealized loss, net of tax, related to the Company's energy-related cash flow hedges under SFAS No. 133 deferred in accumulated other comprehensive income consisted of the following at March 31, 2009 and December 31, 2008:

(DOLLARS IN MILLIONS, NET OF TAX)	MARCH 31, 2009	DECEMBER 31, 2008
Other comprehensive income – unrealized loss	\$ (166.3)	\$ (111.7)

The following table presents natural gas derivative contracts at March 31, 2009 and December 31, 2008:

(DOLLARS IN MILLIONS)	GAS DERIVATIVES	
	MARCH 31, 2009	DECEMBER 31, 2008
Current asset	\$ 20.9	\$ 15.2
Long-term asset	9.3	6.2
Total assets	\$ 30.2	\$ 21.4
Current liability	\$ 172.4	\$ 146.3
Long-term liability	54.4	62.3
Total liabilities	\$ 226.8	\$ 208.6

At March 31, 2009, the Company had total assets of \$30.2 million and total liabilities of \$226.8 million related to financial contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers. All fair value adjustments on derivatives relating to natural gas have been reclassified to a deferred account in accordance with SFAS No. 71 due to the PGA mechanism. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism. As the gains and losses on the hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism.

The ending balance in OCI related to the forward starting swaps and previously settled treasury lock contracts at March 31, 2009 is a net loss of \$7.8 million after tax and accumulated amortization. This compares to a loss of \$7.9 million in OCI after tax and accumulated amortization at December 31, 2008.

SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – An Amendment of Financial Accounting Standards Board (FASB) Statement No. 133" (SFAS No. 161), requires enhanced disclosures about a company's derivative activities and how the related hedged items affect a company's financial position, financial performance and cash flows. To meet the objectives, SFAS No. 161 requires qualitative disclosures about the Company's fair value amounts of gains and losses associated with derivative instruments, as well as disclosures about credit-risk-related contingent features in derivative agreements.

The following table presents the fair values and locations of derivative instruments recorded in the balance sheet at March 31, 2009:

(DOLLARS IN MILLIONS) AT MARCH 31, 2009	DERIVATIVES DESIGNATED AS HEDGING INSTRUMENTS			
	ASSET DERIVATIVES		LIABILITY DERIVATIVES	
	BALANCE SHEET LOCATION	FAIR VALUE	BALANCE SHEET LOCATION	FAIR VALUE
Commodity contracts:				
Electric derivatives:				
Current	Unrealized gain on derivative instruments	\$ --	Unrealized loss on derivative instruments	\$ 145.6
Long term	Unrealized gain on derivative instruments	0.3	Unrealized loss on derivative instruments	120.0
Gas derivatives:				
Current	Unrealized gain on derivative instruments	--	Unrealized loss on derivative instruments	--
Long term	Unrealized gain on derivative instruments	--	Unrealized loss on derivative instruments	--
Total derivatives designated as hedging instruments		\$ 0.3		\$ 265.6

(DOLLARS IN MILLIONS) AT MARCH 31, 2009	DERIVATIVES NOT DESIGNATED AS HEDGING INSTRUMENTS			
	ASSET DERIVATIVES		LIABILITY DERIVATIVES	
	BALANCE SHEET LOCATION	FAIR VALUE	BALANCE SHEET LOCATION	FAIR VALUE
Commodity contracts:				
Electric derivatives:				
Current	Unrealized gain on derivative instruments	\$ 1.2	Unrealized loss on derivative instruments	\$ 6.3
Long term	Unrealized gain on derivative instruments	0.6	Unrealized loss on derivative instruments	2.2
Gas derivatives:				
Current	Unrealized gain on derivative instruments	20.9	Unrealized loss on derivative instruments	172.4
Long term	Unrealized gain on derivative instruments	9.3	Unrealized loss on derivative instruments	54.4
Total derivatives not designated as hedging instruments		\$ 32.0		\$ 235.3
Combined total		\$ 32.3		\$ 500.9

The following table presents the effect of energy related derivatives on the PGA mechanism in the balance sheet as of March 31, 2009:

(DOLLARS IN MILLIONS) AT MARCH 31, 2009	BALANCE SHEET LOCATION ¹	FAIR VALUE	BALANCE SHEET LOCATION ¹	FAIR VALUE
Commodity contracts:				
Gas derivatives:				
Current	Other regulatory assets	\$ 196.6	Regulatory liabilities	\$ --
Total		\$ 196.6		\$ --

¹ Natural gas derivatives are deferred, in accordance with SFAS No. 71 and all increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism. As gains and losses are realized in future periods, they will be recorded as purchased gas costs in the income statement.

The following table presents the effect of hedging instruments on OCI and income for the three months ended March 31, 2009:

(DOLLARS IN MILLIONS)	AMOUNT OF LOSS RECOGNIZED IN OCI ON DERIVATIVES	LOCATION OF LOSS RECLASSIFIED FROM ACCUMULATED OCI INTO INCOME	AMOUNT OF LOSS RECLASSIFIED FROM ACCUMULATED OCI INTO INCOME	LOCATION OF LOSS RECOGNIZED IN INCOME ON DERIVATIVES	AMOUNT OF LOSS RECOGNIZED IN INCOME ON DERIVATIVES
DERIVATIVES IN SFAS No. 133 CASH FLOW HEDGING RELATIONSHIPS	EFFECTIVE PORTION ¹	EFFECTIVE PORTION ²		INEFFECTIVE PORTION AND AMOUNT EXCLUDED FROM EFFECTIVENESS TESTING ^{2,3}	
Interest rate contracts:	\$ --	Interest expense	\$ (0.1)		\$ --
Commodity contracts:				Net unrealized loss on derivative instruments	--
Electric derivatives	(48.5)	Electric generation fuel	(21.5)		
Electric derivatives	(19.4)	Purchased electricity	--	Net unrealized loss on derivative instruments	(3.2)
Gas derivatives	--	Purchased gas	--	Net unrealized loss on derivative instruments	--
Total	\$ (67.9)		\$ (21.6)		\$ (3.2)

¹ Changes in OCI are reported in after tax dollars.

² Losses are reported in pre-tax dollars.

³ Ineffective portion of long-term power supply contracts that are designated as cash flow hedges.

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivatives representing hedge ineffectiveness are recognized in current earnings. The Company expects that in the future it may be extremely difficult to qualify for cash flow hedge treatment due to market conditions. The Company expects that \$88.6 million of losses in OCI will be reclassified into earnings within the next 12 months. The maximum length of time over which the Company is hedging its exposure to the variability in future cash flows extends to February 2015 for the physical electric contracts and to January 2012 for electric generation fuel financial contracts.

The following table presents the effect of derivatives not designated as hedging instruments on income for the three months ended March 31, 2009:

(DOLLARS IN MILLIONS) THREE MONTHS ENDED MARCH 31, 2009	LOCATION OF GAIN IN INCOME ON DERIVATIVES	AMOUNT OF GAIN RECOGNIZED IN INCOME ON DERIVATIVES
Interest rate contracts:		\$ --
Commodity contracts:	Net unrealized gain on derivative instruments	0.9
Electric derivatives		
Gas derivatives	Net unrealized gain on derivative instruments	--
Total		\$ 0.9

For the quarter ended March 31, 2009, the Company reported \$4.8 million in losses that were reclassified into earnings as a result of the discontinuance of cash flow hedges because the original forecasted transactions have a remote chance of occurring. The Company also reported year-to-date gains of \$5.7 million related to transactions that did not meet NPNS or cash flow hedge criteria.

The Company had the following outstanding commodity contracts that were entered into as of March 31, 2009:

THREE MONTHS ENDED MARCH 31, 2009	NUMBER OF UNITS
Derivatives designated as hedging instruments:	
Electric generation fuel	61,660,000 MMBtus
Purchased electricity	4,812,300 MWh
Derivatives not designated as hedging instruments:	
Gas derivatives ¹	86,021,684 MMBtus
Electric generation fuel	5,228,960 MMBtus
Purchased electricity	2,635,400 MWh

¹ Gas derivatives are deferred in accordance with SFAS No. 71.

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

Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate the potential credit default losses. Criteria employed in this decision includes, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.

The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies or have changes in ownership.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of March 31, 2009, approximately 99.6% of the counterparties with transaction amounts outstanding in the Company's energy portfolio, including NPNS transactions, are rated at least investment grade by the major rating agencies and 0.4% are either rated below investment grade or are not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

The Company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The Company generally enters into the following master arrangements: (1) Western Systems Power Pool agreements (WSPP) - standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) - standardized financial gas and electric contracts; and (3) North American Energy Standards Board agreements (NAESB) - standardized physical gas contracts. The Company believes that entering into such agreements reduces the risk of default by allowing a counterparty the ability to make only one net payment.

The Company computes credit reserves at a master agreement level (i.e. WSPP, ISDA or NAESB) by counterparty. The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives counterparty's risk of default. The Company uses both default factors published by Standard & Poor's (S&P) and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is used by weighting fair values and contract tenors for all deals for each counterparty and coming up with an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. Moreover, the Company applies its own default factor to compute credit reserves for counterparties in a net liability position. The Company's S&P rating at March 31, 2009 was BBB. Credit reserves are booked as contra accounts to unrealized gain (loss) positions. As of March 31, 2009, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the year. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electric Coordinating Council.

The Company enters into energy contracts with various credit-risk-related contingent features, which could result in a counterparty requesting immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in a net liability position.

The table below presents the fair value of the overall contractual contingent liability positions for the Company's derivative activity at March 31, 2009:

(DOLLARS IN MILLIONS) AT MARCH 31, 2009			
CONTINGENT FEATURE	FAIR VALUE ⁴ LIABILITY	POSTED COLLATERAL	CONTINGENT COLLATERAL
Credit rating ¹	\$ (4.0)	\$ --	\$ 4.0
Reasonable grounds for adequate assurance ²	(143.4)	--	--
Forward value of contract ³	(60.2)	35.0	N/A
Total	\$ (207.6)	\$ 35.0	\$ 4.0

¹ The Company is required to maintain an investment grade credit rating from each of the major credit rating agencies.

² A counterparty with reasonable grounds for insecurity regarding performance of an obligation may request adequate assurance of performance.

³ Collateral requirements may vary, based on changes in forward value of underlying transactions.

⁴ Represents derivative fair values of contracts with contingent features for counterparties in net derivative liability positions at March 31, 2009. Excludes NPNS and accounts payable and accounts receivable activity.

(4) Fair Value Measurements

SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities. Equity securities that are also classified as cash equivalents are considered Level 1 if there are unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter forwards and options.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. At each balance sheet date, the Company performs an analysis of all

instruments subject to SFAS No. 157 and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. If a fair value measurement relies on inputs from different levels of the hierarchy, the entire measurement must be placed into the same level based on the lowest level input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of the Company's nonperformance risk on its liabilities.

As of March 31, 2009, the Company considers the markets for its electric and natural gas Level 2 derivative instruments to be actively traded. Management's assessment is based on the trading activity volume in real-time and forward electric and natural gas markets. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter.

The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009:

RECURRING FAIR VALUE MEASURES (DOLLARS IN MILLIONS)	AT FAIR VALUE AS OF MARCH 31, 2009				AT FAIR VALUE AS OF MARCH 31, 2008			
	LEVEL 1	LEVEL 2	LEVEL 3	TOTAL	LEVEL 1	LEVEL 2	LEVEL 3	TOTAL
Assets:								
Energy derivative instruments	\$ --	\$ 31.5	\$ 0.9	\$ 32.4	\$ --	\$ 107.8	\$ 34.6	\$ 142.4
Money market accounts	63.9	--	1.4	65.3	13.8	--	1.4	15.2
Total assets	\$ 63.9	\$ 31.5	\$ 2.3	\$ 97.7	\$ 13.8	\$ 107.8	\$ 36.0	\$ 157.6
Liabilities:								
Energy derivative instruments	\$ --	\$ 322.5	\$ 178.5	\$ 501.0	\$ --	\$ 1.4	\$ 10.2	\$ 11.6
Other financial items	--	--	--	--	--	--	7.2	7.2
Total liabilities	\$ --	\$ 322.5	\$ 178.5	\$ 501.0	\$ --	\$ 1.4	\$ 17.4	\$ 18.8

The following table sets forth a reconciliation of changes in the fair value of derivatives classified as Level 3 in the fair value hierarchy:

(DOLLARS IN MILLIONS)	2009	2008
Balance at beginning of period (net credit reserve on energy derivatives)	\$ (132.2)	\$ (7.3)
Changes during period :		
Realized and unrealized energy derivatives		
- included in earnings	(2.4)	(0.1)
- included in other comprehensive income	(53.1)	28.7
- included in regulatory assets/liabilities	(7.4)	0.3
Purchases, issuances, and settlements	8.1	(1.9)
Energy derivatives transferred in/out of Level 3	10.8	(1.1)
Balance as of March 31, 2009 (net credit reserve on energy derivatives)	\$ (176.2)	\$ 18.6

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's income statement under purchased electricity, electric generation fuel or purchased gas when settled.

Unrealized gains and losses for Level 3 inputs on energy derivatives recurring items are included in the net unrealized (gain) loss on derivative instruments section in the Company's income statement and as net unrealized (gain) loss on derivative instruments in OCI. The Company does not believe that the fair values diverge materially from the amounts the Company currently anticipates realizing on settlement or maturity.

Energy derivative instruments are classified as Level 3 in the fair value hierarchy because Level 3 inputs are significant to their fair value measurement. Energy derivatives transferred out of Level 3 represent existing assets or liabilities that were classified as Level 3 at end of the prior reporting period for which the lowest significant input became observable during the

current reporting period. The net unrealized loss recognized during the reporting period is primarily due to a significant decrease in market prices.

(5) Retirement Benefits

The Company has a defined benefit pension plan covering substantially all PSE employees, with a cash balance feature for all but International Brotherhood of Electrical Workers employees. Benefits are a function of age, salary and service. The Company also maintains a non-qualified supplemental retirement plan for officers and certain director-level employees.

The following table summarizes the estimate of net periodic benefit cost for the three months ended March 31:

	QUALIFIED PENSION BENEFITS		SERP PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2009	2008	2009	2008	2009	2008
Components of net periodic benefit cost:						
Service cost	\$ 3,271	\$ 3,054	\$ 267	\$ 234	\$ 32	\$ 43
Interest cost	6,905	6,498	579	553	266	283
Expected return on plan assets	(10,755)	(10,455)	--	--	(111)	(197)
Amortization of prior service cost	283	161	154	154	21	21
Amortization of net loss (gain)	808	--	221	183	(46)	(199)
Amortization of transition obligation	--	--	--	--	13	13
Net periodic benefit cost (income)	\$ 512	\$ (742)	\$ 1,221	\$ 1,124	\$ 175	\$ (36)

The Company previously disclosed in its financial statements for the year ended December 31, 2008 that it expected contributions by the Company to fund the Supplemental Executive Retirement Plan (SERP) and the other postretirement plans for the year ending December 31, 2009 to be \$4.0 million and \$0.1 million, respectively. The full amount of the pension funding for 2009 is for the Company's non-qualified supplemental retirement plan.

During the three months ended March 31, 2009, payments of benefits related to the Company's non-qualified pension plans were \$0.4 million. Based on this activity, the Company anticipates paying additional benefits of \$3.6 million for the Company's non-qualified pension plan during 2009. During the three months ended March 31, 2009, actual other post-retirement medical benefit plan contributions were \$0.2 million. The Company expects to make additional contributions of approximately \$18.0 million during the remaining periods of 2009.

(6) Regulation and Rates

On April 17, 2009, the Washington Commission issued a final order approving and adopting a settlement agreement that authorized PSE to defer certain ownership and operating costs related to its purchase of the Mint Farm Generation Station (Mint Farm) that will be incurred prior to PSE recovering such costs in electric customer rates. Under Washington State law, a company may defer the costs associated with purchasing and operating a gas plant that complies with the greenhouse gases (GHG) emissions performance standard until the plant is included in rates or for two years from the date of purchase, whichever is sooner. As of March 31, 2009, PSE had established a regulatory asset of \$7.7 million. The prudence of the Mint Farm acquisition, recovery of costs of Mint Farm and compliance with the GHG emissions performance standard will be addressed in the Company's next rate proceeding.

On October 8, 2008, the Washington Commission issued its order in PSE's consolidated electric and natural gas general rate case filed in December 2007, approving a general rate increase for electric customers of \$130.2 million or 7.1% annually, and an increase in natural gas rates of \$49.2 million or 4.6% annually. The rate increases for electric and natural gas customers were effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25% and a capital structure that included 46.0% common equity with a return on equity of 10.15%. The Washington Commission issued a separate order on January 15, 2009, that authorized the continuation of the Power Cost Only Rate Case (PCORC) with certain modifications to which the Washington Commission staff and the Company had agreed. The five procedural modifications to the PCORC include extending the expected procedural schedule from five to six months, limiting the power cost updates to one per PCORC unless an additional update is allowed by the Washington Commission as part of the compliance filing, prohibiting the overlap of PCORC and general rate cases (except for requests for interim rate relief),

shortening data request time from ten to five business days and requiring the Company to provide its future energy resource model projections at the outset of a case.

On September 25, 2008, the Washington Commission approved PSE's requested revisions to its PGA tariff schedules resulting in an increase of \$108.8 million or 11.1% on an annual basis in gas sales revenues effective October 1, 2008. The rate increase was the result of higher costs of natural gas in the forward market and a reduction of the credit for the accumulated PGA payable balance. The PGA rate change will increase PSE's revenue but will not impact the Company's net income as the increased revenue will be offset by increased purchased gas costs.

(7) Litigation

Residential Exchange. Petitioners in several actions in the U. S. Court of Appeals for the Ninth Circuit (Ninth Circuit) against the Bonneville Power Administration (BPA) asserted that BPA acted contrary to law in entering into or performing or implementing a number of agreements, including the amended settlement agreement (and the May 2004 agreement) between BPA and PSE regarding the Residential Exchange Program (REP). Petitioners in several actions in the Ninth Circuit against BPA also asserted that BPA acted contrary to law in adopting or implementing the rates upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period were based. A number of parties claimed that BPA rates proposed or adopted in the BPA rate proceeding to develop BPA rates to be used in the agreements for determining the amounts of money to be paid to PSE by BPA during the period October 1, 2006 through September 30, 2009 are contrary to law and that BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing or implementing such agreements.

On May 3, 2007, the Ninth Circuit issued an opinion in *Portland Gen. Elec. v. BPA*, Case No. 01-70003, in which proceeding the actions of BPA in entering into settlement agreements regarding the REP with PSE and with other investor-owned utilities were challenged. In this opinion, the Ninth Circuit granted petitions for review and held the settlement agreements entered into between BPA and the investor-owned utilities being challenged in that proceeding to be inconsistent with statute. On May 3, 2007, the Ninth Circuit also issued an opinion in *Golden Northwest Aluminum v. BPA*, Case No. 03-73426, in which proceeding the petitioners sought review of BPA's 2002-2006 power rates. In this opinion, the Ninth Circuit granted petitions for review and held that BPA unlawfully shifted onto its preference customers the costs of its settlements with the investor-owned utilities. On October 5, 2007, petitions for rehearing of these two opinions were denied. On February 1, 2008, PSE and other utilities filed in the Supreme Court of the United States a petition for a writ of certiorari to review the decisions of the Ninth Circuit, which petition was denied in June 2008.

In May 2007, following the Ninth Circuit's issuance of these two opinions, BPA suspended payments to PSE under the amended settlement agreement (and the May 2004 agreement). On October 11, 2007, the Ninth Circuit remanded the May 2004 agreement to BPA in light of the *Portland Gen. Elec. v. BPA* opinion and dismissed the remaining three pending cases regarding settlement agreements.

In March 2008, BPA and PSE signed an agreement pursuant to which BPA made a payment to PSE related to the REP benefits for the fiscal year ended September 30, 2008, which payment is subject to true-up depending upon the amount of any REP benefits ultimately determined to be payable to PSE. In March and April 2008, Clatskanie People's Utility District filed petitions in the Ninth Circuit for review of BPA actions in connection with offering or entering into such agreement with PSE and similar agreements with other investor-owned utilities. Clatskanie People's Utility District asserts that BPA's actions in entering into and executing the 2008 REP agreements were contrary to law or without authority and that such agreements are null and void and result in overpayments of REP benefits to PSE and other regional investor-owned utilities.

In September 2008, BPA issued its record of decision in its reopened WP-07 rate proceeding to respond to the various Ninth Circuit opinions. In this record of decision, BPA adjusted its fiscal year 2009 rates, determined the amounts of REP benefits it considered to have been improperly paid after fiscal year 2001 to PSE and the other regional investor-owned utilities, and determined that such amounts are to be recovered through reductions in REP benefit payments to be made over a number of years. The amount determined by BPA to be recovered through reductions commencing October 2007 in REP payments for PSE's residential and small farm customers was approximately \$207.2 million plus interest on unrecovered amounts. However, these BPA determinations are subject to subsequent administrative and judicial review, which may alter or reverse such determinations. PSE and others, including a number of preference agency and investor-owned utility

customers of BPA, in December 2008 filed petitions for review in the Ninth Circuit of various of these BPA determinations. PSE is reviewing its options in determining if it will contest the amounts withheld as improper payments made since 2001.

In September 2008, BPA and PSE signed a short-term Residential Purchase and Sale Agreement (RPSA) under which BPA is to pay REP benefits to PSE for fiscal years ending September 30, 2009–2011. In December 2008, BPA and PSE signed another long-term RPSA under which BPA is to pay REP benefits to PSE for the period October 2011 through September 2028. PSE and other customers of BPA in December 2008 filed petitions for review in the Ninth Circuit of the short-term and long-term RPSAs signed by PSE (and similar RPSAs signed by other investor-owned utility customers of BPA) and BPA's record of decision regarding such RPSAs. Generally, REP benefit payments under a RPSA are based on the amount, if any, by which a utility's average system cost (ASC) exceeds BPA's Priority Firm (PF) Exchange rate for such utility. The ASC for a utility is determined using an ASC methodology adopted by BPA. The ASC methodology adopted by BPA and the ASC determinations, REP overpayment determinations, and the PF Exchange rate determinations by BPA are all subject to Federal Energy Regulatory Commission (FERC) review or judicial review or both and are subject to adjustment, which may affect the amount of REP benefits paid or to be paid by BPA to PSE. As discussed above, BPA has determined to reduce such payments based on its determination of REP benefit overpayments after fiscal year 2001.

It is not clear what impact, if any, such development or review of such BPA rates, review of such ASC, ASC methodology, and BPA determination of REP overpayments, review of such agreements, and the above described Ninth Circuit litigation may ultimately have on PSE. Any changes to the REP payments passes through to customers with no impact to PSE's net income.

Proceedings Related to the Western Power Market. Puget Energy's and PSE's Annual Report on Form 10-K for the year ended December 31, 2008 includes a summary relating to the western power market proceedings. PSE is vigorously defending each of these cases. Litigation is subject to numerous uncertainties and PSE is unable to predict the ultimate outcome of these matters. Accordingly, there can be no guarantee that these proceedings, either individually or in the aggregate, will not materially and/or adversely affect PSE's financial condition, results of operations or liquidity.

CPUC v. FERC. On August 2, 2006, the Ninth Circuit decided that FERC erred in excluding potential relief for tariff violations for periods that pre-dated October 2, 2000 and additionally ruled that FERC should consider remedies for transactions previously considered outside the scope of the proceedings. The August 2, 2006 decision may adversely impact PSE's ability to recover the full amount of its California Independent System Operator (CAISO) receivable. The decision may also expose PSE to claims or liabilities for transactions outside the previously defined "refund period." At this time the ultimate financial outcome for PSE is unclear. Rehearing by the Ninth Circuit was denied on April 6, 2009. Parties have been engaged in court-sponsored settlement discussions, and those discussions may result in some settlements. PSE is unable to predict either the outcome of the proceedings or the ultimate financial effect on PSE.

(8) Related Party Transactions

On June 1, 2006, PSE entered into a revolving credit facility with its parent, Puget Energy, in the form of a Demand Promissory Note (Note). Through the Note, PSE may borrow up to \$30.0 million from Puget Energy, subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted-average interest rate of (a) PSE's outstanding commercial paper interest rate or (b) PSE's senior unsecured revolving credit facility. At March 31, 2009 and December 31, 2008, the outstanding balance of the Note was \$19.4 million and \$26.1 million, respectively and the interest rate was 1.4% and 1.7% respectively. This Note is unaffected by the February 6, 2009 merger.

The Company has a general liability claim from AEGIS Insurance Services Inc. (AEGIS) for \$3.3 million as of March 31, 2009 which was recovered by the Company in April 2009. A PSE management employee serves on one of AEGIS' risk management advisory committees for which no compensation is received.

PSE has property insurance with various companies and approximately 35.0% of the property insurance coverage is with American International Group, Inc (AIG). On October 23, 2008, AIG named the wife of PSE's President and Chief Executive as its Vice Chairman and Chief Restructuring Officer.

(9) Other

In January 2003, FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), as further revised in December 2003 with FIN 46R, which clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have a controlling interest or sufficient equity at risk for the entity to finance its activities without additional financial support.

A variable interest entity (VIE) is an entity in which the equity of the investors as a group do not have: (1) the characteristics of a controlling financial interest; (2) sufficient equity at risk for the entity to finance its activities without additional subordinated financial support; or (3) symmetry between voting rights and economic interests and where substantially all of the entity's activities either involve or are conducted on behalf of an investor with disproportionately few voting rights. Variable interests in a VIE are contractual, ownership or other pecuniary interests in an entity that change with changes in the fair value of the entity's net assets exclusive of variable interest.

FIN 46R requires that if a business entity has a controlling financial interest in a VIE, the financial statements must be included in the consolidated financial statements of the business entity. The adoption of FIN 46R for all interests in VIEs created after January 31, 2003 was effective immediately. For VIEs created before February 1, 2003, it was effective July 1, 2003. The adoption of FIN 46R was effective March 31, 2004 for the Company.

The Company evaluated its power purchase agreements and determined that two power purchase agreements may be considered significant VIEs under FIN 46R. The Company is required to buy all the generation from the two plants, subject to displacement by the Company, at rates set forth in the relevant power purchase agreements. As a result, the Company submitted requests for information to those parties; however, the parties have refused to submit to the Company the necessary information for the Company to determine whether they meet the requirements of a VIE that requires consolidation. The Company will continue to submit requests for information to the counterparties annually to determine if FIN 46R is applicable. PSE's purchased electricity expense for the three months ended March 31, 2009 and 2008 for these entities was \$47.4 million and \$54.9 million, respectively.

In December 2008, FASB issued FIN 46R-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FIN 46R-8), which requires new expanded disclosures in the quarterly financial statements for periods ending after December 15, 2008 for VIEs. The disclosures required by FIN 46R-8 are intended to provide users of the financial statements with greater transparency about a transferor's continuing involvement with transferred financial assets and an enterprise's involvement with VIEs.

A primary beneficiary of a VIE is the variable interest holder (e.g. a contractual counterparty or capital provider) deemed to have the controlling financial interest(s) and is considered to be exposed to the majority of the risks and rewards associated with the VIE and therefore must consolidate it. The Company enters into a variety of contracts for energy with other counterparties and evaluates all contracts for variable interests. The Company's variable interests primarily arise through power purchase agreements where the Company obtains control other than through voting rights and is required to buy all or a majority of generation from a plant at rates set forth in a power purchase agreement, subject to displacement. If a counterparty does not deliver energy to the Company, the Company may have to replace the energy at prices which could be higher or lower than agreed to prices. Therefore, the Company may be exposed to risk associated with replacement costs of a contract.

The Company evaluates variable interest relationships based on significance. If the Company did not participate significantly in the design or redesign of an entity and the variable interest is not considered significant to the Company's financial statements, the variable interest is not considered significant. Purchase power contracts with governmental organizations do not require disclosure. When the Company determines a significant variable interest may exist with another party, the Company requests for information to determine if it is required to be consolidated.

The following table presents the Company's VIE relationships, irrespective of significance, related to power purchase agreements as of March 31, 2009:

VARIABLE INTERESTS IN POWER PURCHASE AGREEMENTS FOR THE MONTH ENDED MARCH 31, 2009				
(DOLLARS IN MILLIONS)				
NATURE OF VARIABLE INTEREST	LONGEST CONTRACT TENOR	NUMBER OF COUNTERPARTIES	AGGREGATE CARRYING VALUE LIABILITY ²	LEVEL OF ACTIVITY - 2009 EXPENSES ²
Electric-combustion turbine co-generation plant ¹	2011	2	\$ (12.4)	\$ 47.4
Electric-hydro	2037	8	(0.6)	2.2
Other	2011	3	--	0.1
Total		13	\$ (13.0)	\$ 49.7

¹ Variable interests may be significant.

² Carrying values are classified in the balance sheet in accounts payable and expenses are classified on the income statement in purchased electricity.

(10) New Accounting Pronouncements

On April 9, 2009, FASB issued FASB Staff Position (FSP) No. 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP No. 157-4). FSP No. 157-4 provides additional guidance for estimating fair value in accordance with SFAS No. 157, when the volume and level of activity for the asset or liability have significantly decreased. FSP No. 157-4 also includes guidance on identifying circumstances that indicate a transaction is not orderly. FSP No. 157-4 will be effective for the Company as of June 30, 2009. The Company is currently assessing the impact of the FSP on its SFAS No. 157 calculations and disclosures.

On April 9, 2009, FASB issued FSP No. 107-1, "Interim Disclosures about Fair Value of Financial Instruments" (FSP No. 107-1). This FSP amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. FSP No. 107-1 also amends APB Opinion No. 28, "Interim Financial Reporting," to require those disclosures in summarized financial information at interim reporting periods. FSP No. 107-1 will be effective for the Company as of June 30, 2009.

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

The following discussion of the Company's financial condition and results of operations contains forward-looking statements that involve risks and uncertainties, such as statements of the Company's plans, objectives, expectations and intentions. Words or phrases 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. Readers should not place undue reliance on these forward-looking statements, which apply only as of the date of this Form 10-Q.

Overview

Puget Sound Energy, Inc. (PSE) is a subsidiary of Puget Energy, Inc. (Puget Energy), an energy services holding company incorporated in the state of Washington in 1999. On February 6, 2009, Puget Holdings LLC (Puget Holdings) completed its merger with Puget Energy. PSE's basis of accounting will continue to be on a historical basis and PSE's financial statements will not include any Statement of Financial Accounting Standards (SFAS) No. 141R, "Business Combinations" purchase accounting adjustments.

PSE is the largest electric and natural gas utility in the state of Washington, primarily engaged in the business of electric transmission, distribution, generation and natural gas distribution. PSE generates revenues primarily from the sale of electric and natural gas services to residential and commercial customers within Washington State. PSE's operating revenues and associated expenses are not generated evenly throughout the year. Variations in energy usage by consumers occur from season to season and from month to month within a season, primarily as a result of weather conditions. PSE normally experiences its highest retail energy sales and subsequently higher power costs during the winter heating season in the first and fourth quarters of the year and its lowest sales in the third quarter of the year. Varying wholesale electric prices and the amount of hydroelectric energy supplies available to PSE also make quarter-to-quarter comparisons difficult.

As a regulated utility company, PSE is subject to Federal Energy Regulatory Commission (FERC) regulations, North American Electric Reliability Corporation (NERC) standards and Washington Utilities and Transportation Commission (Washington Commission) regulations which affects a wide array of business activities, including regulating 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 attainment of PSE's business objectives. In addition, PSE is subject to risks inherent to the utility industry as a whole, including weather changes affecting purchases and sales of energy; outages at owned and non-owned generation plants where energy is obtained; storms or other events which can damage natural gas and electric distribution and transmission lines; increasing regulatory standards for system reliability and wholesale market stability over time; and significant evolving environmental legislation.

PSE is investing heavily in its utility infrastructure and customer service functions in order to meet increasing regulatory requirements, customer growth and aging infrastructure needs. Such investments and operating requirements give rise to significant growth in depreciation expense and operating expense which costs are not timely recovered via the ratemaking process which relies predominately on a historic test year to fix rates and revenue requirements. Such "regulatory lag" is expected to continue for the foreseeable future.

PSE's main business objective is to provide reliable, safe and cost-effective energy to its customers. To help accomplish this objective, PSE seeks to become more energy efficient and environmentally responsible in its energy supply portfolio. PSE filed its most recent Integrated Resource Plan (IRP) on May 31, 2007 with the Washington Commission. The 2007 IRP demonstrated PSE's need to acquire significant amounts of new generating resources, driven primarily by expiration of existing purchase power contracts. The plan supports a strategy of significantly increasing energy efficiency programs, pursuing additional renewable resources (primarily wind) and additional base load natural gas-fired generation to meet the growing needs of its customers. The next IRP will be filed in July 2009.

On January 16, 2009, Standard & Poor's (S&P) Rating Services raised its corporate credit rating on PSE and removed PSE from its watch list for negative implications citing a stable outlook. The rating actions reflected the completion of the

acquisition of Puget Energy and PSE by Puget Holdings. On February 2, 2009, Moody's Investors Service (Moody's) affirmed the long-term ratings of PSE. The ratings outlook for PSE is stable. PSE's equity ratio increased from 38.0% at December 31, 2008 to 50.2% at March 31, 2009.

NON-GAAP FINANCIAL MEASURES – ENERGY MARGINS

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as two other financial measures, electric margin and gas margin, that are considered “non-GAAP financial measures.” Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric margin and gas margin is intended to supplement investors' understanding of the Company's operating performance. Electric margin and gas margin are used by the Company to determine whether the Company is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. The Company's electric margin and gas margin measures may not be comparable to other companies' electric margin and gas margin measures. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Results of Operations

PSE's operating revenues and expenses are not generated evenly throughout the year. Variations in energy usage by customers occur from season to season and from month to month within a season, primarily as a result of weather conditions. PSE normally experiences its highest retail energy sales and subsequently higher power costs during the winter heating season in the first and fourth quarters of the year and its lowest sales in the third quarter of the year. Power cost recovery is seasonal, with underrecovery normally in the first and fourth quarters when electric sales volumes and power costs are higher and overrecovery in the second and third quarters. Varying wholesale electric prices and the amount of hydroelectric energy supplies available to PSE also make quarter to quarter comparisons difficult.

Net income for the three months ended March 31, 2009 was \$85.0 million on operating revenues of \$1.1 billion as compared to net income of \$80.9 million on operating revenues of \$1.0 billion for the same period in 2008.

Net income for the three months ended March 31, 2009 as compared to the same period in 2008 was positively impacted by a \$26.3 million pre-tax increase in electric margin and a \$12.1 million pre-tax increase in gas margin. Electric and natural gas margins were favorably impacted by general tariff rate increases of 7.1% and 4.6%, respectively, that were approved by the Washington Commission and were effective November 1, 2008. The favorable impact of lower natural gas prices and wholesale power costs was offset by below normal hydroelectric energy production during the first quarter of 2009. Net income was negatively impacted by one-time merger costs of \$27.6 million related to the merger of Puget Energy with Puget Holdings. These costs were primarily related to PSE employee compensation triggered by the Puget Energy's change of control, credit agreement related expenses and the income statement impact of deferred compensation related liability increases triggered by the merger. In addition, net income was negatively impacted due to an increase in depreciation and amortization of \$6.0 million.

ENERGY MARGINS

The following table displays the details of electric margin changes for the three months ended March 31, 2009 as compared to the same period in 2008. Electric margin is electric sales to retail and transportation customers less pass-through tariff items, 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 MARCH 31,	ELECTRIC MARGIN			PERCENT CHANGE
	2009	2008	CHANGE	
Electric operating revenue ¹	\$ 600.2	\$ 606.1	\$ (5.9)	(1.0) %
Less: Other electric operating revenue	(0.8)	(12.2)	11.4	93.4
Add: Other electric operating revenue-gas supply resale	(8.9)	2.6	(11.5)	*
Total electric revenue for margin	590.5	596.5	(6.0)	(1.0)
Adjustments for amounts included in revenue:				
Pass-through tariff items	(21.7)	(12.9)	(8.8)	(68.2)
Pass-through revenue-sensitive taxes	(44.4)	(41.6)	(2.8)	(6.7)
Net electric revenue for margin	524.4	542.0	(17.6)	(3.2)
Minus power costs:				
Purchased electricity ¹	(260.2)	(272.8)	12.6	4.6
Electric generation fuel ¹	(48.1)	(47.0)	(1.1)	(2.3)
Residential exchange ¹	32.4	--	32.4	*
Total electric power costs	(275.9)	(319.8)	43.9	13.7
Electric margin ²	\$ 248.5	\$ 222.2	\$ 26.3	11.8 %

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

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

* Percent change not applicable or meaningful.

Electric margin increased \$26.3 million for the three months ended March 31, 2009 as compared to the same period in 2008. The increase in electric margin was primarily due to a general rate case increase of 7.1% effective November 1, 2008 and favorable impact of lower natural gas and wholesale power prices offset by below normal hydroelectric energy production during the first quarter 2009 which increased margin by \$28.3 million. With lower natural gas prices, PSE increased its generation from its gas-fired generating facilities. This increase was partially offset by a 0.5% decrease in retail kilowatt hour (kWH) sales and other items which decreased margin by \$1.9 million.

The following table displays the details of gas margin changes for the three months ended March 31, 2009 as compared to the same period in 2008. Gas margin is natural gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of natural gas purchased, including transportation costs to bring natural gas to PSE's service territory.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED MARCH 31,	GAS MARGIN			PERCENT CHANGE
	2009	2008	CHANGE	
Gas operating revenue ¹	\$ 506.4	\$ 443.2	\$ 63.2	14.3 %
Less: Other gas operating revenue	(4.9)	(4.6)	(0.3)	(6.5)
Total gas revenue for margin	501.5	438.6	62.9	14.3
Adjustments for amounts included in revenue:				
Pass-through tariff items	(4.7)	(4.4)	(0.3)	(6.8)
Pass-through revenue-sensitive taxes	(41.6)	(35.0)	(6.6)	(18.9)
Net gas revenue for margin	455.2	399.2	56.0	14.0
Minus purchased gas costs ¹	(320.1)	(276.2)	(43.9)	(15.9)
Gas margin ²	\$ 135.1	\$ 123.0	\$ 12.1	9.8 %

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

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

Gas margin increased \$12.1 million for the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to the general rate case increase of 4.6% effective November 1, 2008 which increased margin by \$20.4 million. This increase was partially offset by a decrease in margin of \$6.4 million due to customer mix and other pricing variances and a decrease of \$1.9 million due to a 1.6% decrease in gas therm volume.

ELECTRIC OPERATING REVENUES

The table below sets forth changes in electric operating revenues for PSE for the three months ended March 31, 2009 as compared to the same period in 2008.

(DOLLARS IN MILLIONS)				
THREE MONTHS ENDED MARCH 31,	2009	2008	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	\$ 358.8	\$ 346.6	\$ 12.2	3.5 %
Commercial sales	231.6	212.0	19.6	9.2
Industrial sales	26.5	27.5	(1.0)	(3.6)
Other retail sales, including unbilled revenue	(29.4)	(11.6)	(17.8)	*
Total retail sales	587.5	574.5	13.0	2.3
Transportation sales	2.5	1.5	1.0	66.7
Sales to other utilities and marketers	9.3	18.0	(8.7)	(48.3)
Other	0.9	12.1	(11.2)	(92.6)
Total electric operating revenues	\$ 600.2	\$ 606.1	\$ (5.9)	(1.0) %

* Percent change not applicable or meaningful.

Electric retail sales increased \$13.0 million for the three months ended March 31, 2009 as compared to the same period in 2008. The increase was due in part to the electric general rate increase of November 1, 2008 partially offset by a merger rate credit effective February 13, 2009, which combined, contributed to an increase in electric retail sales of \$41.4 million for 2009 as compared to 2008. Electric retail sales also increased by \$7.5 million as a result of an increase in the conservation rider charged to customers due to an increase in the Company's energy efficiency programs, which has no impact on net income as the amount is offset in conservation amortization. These increases were partially offset by a decrease in retail electricity usage of 30,346 megawatt hours (MWh) or 0.5% for 2009 as compared to the same period in 2008, which resulted in a decrease of approximately \$2.9 million to electric operating revenue. The benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by \$33.9 million in 2009. This credit also reduced power costs and revenue sensitive taxes by a corresponding amount with no impact on earnings.

Sales to other utilities and marketers decreased \$8.7 million for the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to a decrease in wholesale electric energy prices which decreased revenue by of \$9.1 million. This decrease was partially offset by an increase in other items.

Other electric operating revenues decreased \$11.2 million for the three months ended March 31, 2009 as compared to the same period in 2007 primarily due to a decrease of \$11.5 million in noncore gas sales and related losses from hedging contracts entered into to manage those noncore gas sales.

The following electric rate changes were approved by the Washington Commission in 2008 and 2009:

TYPE OF RATE ADJUSTMENT	EFFECTIVE DATE	AVERAGE PERCENTAGE INCREASE (DECREASE) IN RATES	ANNUAL INCREASE (DECREASE) IN REVENUES (DOLLARS IN MILLIONS)
Electric General Rate Case	November 1, 2008	7.1 %	\$130.2
Merger Rate Credit	February 13, 2009	(0.4)%	\$ (6.7)

GAS OPERATING REVENUES

The table below sets forth changes in gas operating revenues for PSE for the three months ended March 31, 2009 as compared to the same period in 2008.

(DOLLARS IN MILLIONS)				PERCENT
THREE MONTHS ENDED MARCH 31,	2009	2008	CHANGE	CHANGE
Gas operating revenues:				
Residential sales	\$ 344.2	\$ 294.2	\$ 50.0	17.0 %
Commercial sales	139.4	127.8	11.6	9.1
Industrial sales	14.8	12.8	2.0	15.6
Total retail sales	498.4	434.8	63.6	14.6
Transportation sales	3.1	3.8	(0.7)	(18.4)
Other	4.9	4.6	0.3	6.5
Total gas operating revenues	\$ 506.4	\$ 443.2	\$ 63.2	14.3 %

Gas retail sales increased \$63.6 million for the three months ended March 31, 2009 as compared to the same period in 2008 due to a \$64.8 million increase in gas operating revenues as a result of a 11.1% Purchased Gas Adjustment (PGA) mechanism rate increase for retail customers effective October 1, 2008 and a general rate increase effective November 1, 2008. The PGA mechanism passes through to customers increases or decreases in the natural gas supply portion of the natural gas service rates based upon changes in the price of natural gas purchased from producers and wholesale marketers or changes in natural gas pipeline transportation costs. PSE's gas margin and net income are not affected by changes under the PGA mechanism. Partially offsetting the increase was a 1.0 million decrease in gas therm sales which decreased margin \$1.3 million.

The following natural gas rate adjustments were approved by the Washington Commission in 2008 and 2009:

TYPE OF RATE		AVERAGE	ANNUAL
ADJUSTMENT	EFFECTIVE DATE	PERCENTAGE	INCREASE (DECREASE)
		INCREASE (DECREASE)	IN REVENUES
		IN RATES	(DOLLARS IN MILLIONS)
Purchased Gas Adjustment	October 1, 2008	11.1 %	\$ 108.8
General Rate Case	November 1, 2008	4.3 %	\$ 49.2
Merger Rate Credit	February 13, 2009	(0.4)%	\$ (3.6)

OPERATING EXPENSES

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries for the three months ended March 31, 2009 as compared to the same period in 2008.

(DOLLARS IN MILLIONS)				PERCENT
THREE MONTHS ENDED MARCH 31,	2009	2008	CHANGE	CHANGE
Purchased electricity	\$ 260.3	\$ 272.8	\$ (12.5)	(4.6) %
Residential exchange	(32.4)	--	(32.4)	*
Purchased gas	320.1	276.2	43.9	15.9
Utility operations and maintenance	114.9	112.2	2.7	2.4
Merger and related costs	27.6	--	27.6	*
Depreciation and amortization	81.4	75.4	6.0	8.0
Conservation amortization	20.8	13.4	7.4	55.2
Taxes other than income taxes	101.3	94.3	7.0	7.4

* Percent change not applicable or meaningful.

Purchased electricity expenses decreased \$12.5 million for the three months ended March 31, 2009 as compared to the same period in 2008. The decrease is related to lower wholesale power prices and increased generation at PSE's gas-fired generating facilities due to lower cost of natural gas in the three months ended March 31, 2009 as compared to the same period in 2008, which resulted in a decrease of \$13.1 million. PSE utilizes less purchased power when the cost of natural gas

is lower than the cost of wholesale purchased power due to its recent acquisitions of the Goldendale and Mint Farm gas-fired generating facilities, which have low heat rates. This decrease was partially offset by an increase of \$0.6 million in transmission and other expenses.

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.

Residential exchange credits associated with the Bonneville Power Administration (BPA) Residential Exchange Program (REP) increased to \$32.4 million for the three months ended March 31, 2009 as a result of an agreement with BPA to continue to pass on REP benefits to PSE's customers. REP does not have an impact on net income.

Purchased gas expenses increased \$43.9 million for the three months ended March 31, 2009 as compared to the same period in 2008 primarily due to an increase of 11.1% in PGA rates which provides the rates used to determine gas costs based on customer usage. The rate increase was the result of higher costs of natural gas in the forward market and a reduction of the credit for accumulated PGA payable balance. The PGA mechanism allows PSE to recover expected natural gas supply and transportation costs, and defer, as a receivable or liability, any natural gas supply and transportation costs that exceed or fall short of this expected gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism payable balance at March 31, 2009 was \$29.7 million as compared to \$8.9 million at December 31, 2008. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable balance in the PGA mechanism reflects an under recovery of market natural gas cost through rates. A payable balance reflects over recovery of market natural gas cost through rates.

Utility operations and maintenance expense increased \$2.7 million for the three months ended March 31, 2009 as compared to the same period in 2008. The increase for the three months ended March 31, 2009 was primarily due to an increase in administrative and general expenses of \$3.1 million which included increases in salary and employee benefits expense, an increase in rent expense and an increase in property insurance costs, customer service costs of \$3.0 million, electric transmission and distribution costs of \$1.9 million and a \$1.6 million increase in gas operations and distribution expenses. These increases were partially offset by a \$7.8 million decrease in production operations and maintenance costs related to settlement of a lawsuit at the Colstrip generating facilities.

Merger and related costs associated with the merger with Puget Holdings incurred for the three months ended March 31, 2009 were \$27.6 million. These costs include compensation costs as a result of the change in control, write-off of deferred debt costs associated with the termination of the pre-merger credit facilities, expenses associated with new credit facilities and the impact of deferred compensation liabilities as a result of the merger. Pursuant to the Washington Commission merger order commitments, PSE will not seek recovery of these costs.

Depreciation and amortization expense increased \$6.0 million for the three months ended March 31, 2009 as compared to the same period in 2008. Excluding the regulatory credit for the deferral of Mint Farm Generation Station (Mint Farm) fixed costs of \$3.8 million, depreciation and amortization expense increased \$9.8 million for the three months ended March 31, 2009 as compared to the same period in 2008. This increase is due to additional depreciable property placed into service and an increase in storm amortization costs as approved in PSE's general rate case effective November 1, 2008.

Conservation amortization increased \$7.4 million for the three months ended March 31, 2009 as compared to the same period in 2008 due to higher authorized recovery of electric conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes increased \$7.0 million for the three months ended March 31, 2009 as compared to the same period in 2008. Revenue sensitive taxes increased \$9.3 million due to an increase in revenue offset by a decrease of \$2.7 million in property taxes from a true-up of accrued property taxes recorded for 2008.

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following are PSE's aggregate consolidated commercial commitments as of March 31, 2009:

COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD			
		2009	2010- 2011	2012- 2013	2014 & THEREAFTER
Working capital facility	\$ 225.0	\$ --	\$ --	\$ --	\$ 225.0
Capital expenditure facility	400.0	--	--	--	400.0
Energy hedging facility	315.0	--	--	--	315.0
Energy operations letter of credit	6.6	6.6	--	--	--
Energy hedging letter of credit	35.0	35.0	--	--	--
Total commercial commitments	\$ 981.6	\$ 41.6	\$ --	\$ --	\$ 940.0

The following are PSE's aggregate contractual obligations and commercial commitments as of March 31, 2009:

CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	TOTAL	PAYMENTS DUE PER PERIOD			
		2009	2010- 2011	2012- 2013	2014 & THEREAFTER
Long-term debt including interest	\$ 6,243.9	\$ 146.3	\$ 809.6	\$ 305.7	\$ 4,982.3
Short-term debt including interest	194.5	194.5	--	--	--
Service contract obligations	398.3	51.9	129.2	82.3	134.9
Non-cancelable operating leases	193.6	47.4	28.9	27.7	89.6
Fredonia gas-fired generating facility lease ¹	46.3	46.3	--	--	--
Energy purchase obligations	4,796.2	645.5	1,635.2	772.0	1,743.5
Contract initiation payment/collateral requirement	18.5	--	18.5	--	--
Financial hedge obligations	112.6	59.7	52.9	--	--
Purchase obligations	130.1	73.1	6.6	6.8	43.6
Non-qualified pension and other benefits funding and payments	67.8	21.5	8.8	9.9	27.6
Total contractual cash obligations	\$ 12,201.8	\$ 1,286.2	\$ 2,689.7	\$ 1,204.4	\$ 7,021.5

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

OFF-BALANCE SHEET ARRANGEMENTS

Fredonia 3 and 4 Operating Lease. PSE leases two gas-fired turbines for its Fredonia 3 and 4 generating facility pursuant to a master operating lease that was amended for this purpose in April 2001. On November 14, 2008, GE Capital Commercial Inc. notified PSE of its intentions to cancel the lease effective January 14, 2009. PSE intends to purchase the gas-fired turbines by January 2010. Payments under the lease vary with changes in the London Interbank Offered Rate (LIBOR). At March 31, 2009, PSE's outstanding balance under the lease was \$44.7 million. The expected residual value under the lease is the lesser of \$42.3 million or 60.0% of the cost of the equipment.

UTILITY CONSTRUCTION PROGRAM

PSE's construction programs for generating facilities, the electric transmission system and the natural gas and electric distribution systems are designed to meet continuing customer growth and to support reliable energy delivery. The cash flow construction expenditures, excluding equity Allowance for Funds Used During Construction (AFUDC) and customer refundable contributions, was \$177.7 million for the three months ended March 31, 2009. The anticipated utility construction expenditures, excluding AFUDC, for 2009, 2010 and 2011 are:

CAPITAL EXPENDITURE ESTIMATES (DOLLARS IN MILLIONS)				
	2009		2010	2011
Energy delivery, technology and facilities	\$	687	\$	840
New supply resources		234		621
Total expenditures	\$	921	\$	1,461
				\$ 1,132

The proposed utility construction expenditures and any new generation resource expenditures that may be incurred are anticipated to be funded with a combination of cash from operations, short-term debt, long-term debt and equity. Construction expenditure estimates, including any new generation resources, are subject to periodic review and adjustment in light of changing economic, regulatory, environmental and efficiency factors.

CAPITAL RESOURCES

CASH FROM OPERATIONS

Cash generated from operations for the three months ended March 31, 2009 was \$213.9 million, a decrease of \$118.8 million from the \$332.7 million generated during the first quarter of 2008. The decrease was primarily the result of an increase of \$118.7 million in natural gas payments and payment of gas financial hedge contracts, power cost and other payable balances as compared to the same period in 2008. Further, PSE received a refund of \$39.7 million in income taxes in the first quarter 2008 compared to a refund of \$0.2 million in 2009 which resulted in a decrease of \$39.5 million in the current quarter. Also contributing to the decrease in operating activities was a Colstrip legal settlement accrual of \$10.5 million in the first quarter 2008 and an increase in fuel and gas inventories and materials and supplies of \$18.2 million over the same period in 2008. PSE increased first quarter 2009 prepayments by \$13.0 million compared to the same period in 2008.

The decrease in cash generated from operating activities for the first quarter 2009 as compared to 2008 was partially offset by overrecovery of natural gas costs through the PGA mechanism during the first quarter 2009 of \$20.8 million compared to an underrecovery of \$9.4 million during the same period in 2008 which increased operating activities by \$30.2 million. Further, PSE collected \$21.5 million in accounts receivable in 2009 over 2008.

FINANCING PROGRAM

Financing utility construction requirements and operational needs are dependent upon the amount of cash available and the cost and availability of external funds through capital markets. PSE anticipates refinancing the redemption of bonds with its liquidity facilities and/or the issuance of new bonds. Access to funds depends upon factors such as general economic conditions, regulatory climate and policies and PSE's credit ratings.

On January 23, 2009, PSE issued \$250.0 million of first mortgage bonds. The bonds were placed with approximately 35 institutional investors, have a term of seven years and carry a 6.75% coupon.

LIQUIDITY FACILITIES AND COMMERCIAL PAPER

PSE's short-term borrowings and sales of commercial paper are used to provide working capital and funding of utility construction programs. PSE has not been significantly impacted by the recent disruption in the credit environment.

PSE CREDIT FACILITIES

Credit Agreements. Effective immediately after the merger on February 6, 2009, PSE has three committed unsecured revolving credit facilities that provide, in aggregate, \$1.15 billion in short-term borrowing capability. These new facilities

include a \$400.0 million credit agreement for working capital needs, a \$400.0 million credit facility for funding capital expenditures and a \$350.0 million facility to support other working capital and energy hedging activities.

These facilities mature in February 2014 and each contain similar terms and conditions and are syndicated among numerous banks. The agreements provide PSE with the ability to borrow at either a base rate (which is based on the Prime Rate) or the Eurodollar rate (which is based on the LIBOR), plus a spread. The Company must also pay a commitment fee on the unused portion of the facilities. The spread and the commitment fee depend on PSE's credit ratings as determined by S&P and Moody's. At the Company's current credit ratings, the spread is 85 basis points and the commitment fee is 26 basis points. The \$400.0 million working capital facility and \$350.0 million credit agreement to support energy hedging permit the issuance of standby letters of credit up to the entire amount of the credit agreements. The \$400.0 million working capital facility also serves as a backstop for PSE's commercial paper program.

As of March 31, 2009, PSE had borrowed \$175.0 million on the \$400.0 million working capital facility and had a \$35.0 million letter of credit outstanding under the \$350.0 million facility. There were no borrowings under the \$400.0 million capital expenditure facility as of March 31, 2009. In addition to the credit agreements, PSE had a \$6.6 million letter of credit through a bank in support of a long-term transmission contract.

Demand Promissory Note. On June 1, 2006, PSE entered into an uncommitted revolving credit facility with its parent, Puget Energy, pursuant to a Demand Promissory Note (Note) under which PSE may borrow up to \$30.0 million from Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted-average interest rate of (a) PSE's outstanding commercial paper interest rate or (b) PSE's senior unsecured revolving credit facility. At March 31, 2009, the outstanding balance of the Note was \$19.4 million. This Note is unaffected by the February 6, 2009 merger.

LONG-TERM FUNDING AND RESTRICTIVE COVENANTS

In determining the type and amount of future financing, PSE may be limited by restrictions contained in its electric and natural gas mortgage indentures, restated articles of incorporation and certain loan agreements. Under the most restrictive tests, at March 31, 2009, PSE could issue:

- approximately \$1.0 billion of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately \$1.7 billion of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest (as defined in the electric utility mortgage), which PSE exceeded at March 31, 2009;
- approximately \$560.0 million of additional first mortgage bonds under PSE's natural gas mortgage indenture based on approximately \$930.0 million of gas bondable property available for issuance, subject to interest coverage ratio limitations of 1.75 times and 2.0 times net earnings available for interest (as defined in the natural gas utility mortgage), which PSE exceeded at March 31, 2009;

At March 31, 2009, PSE had approximately \$5.1 billion in electric and natural gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

CREDIT RATINGS

PSE has no debt outstanding that would accelerate debt maturity upon a credit rating downgrade. A ratings downgrade could adversely affect the ability to renew existing, or obtain access to new credit facilities and could increase the cost of such facilities. For example, under PSE's revolving credit facility, the borrowing costs and commitment fee increase as PSE's corporate/issuer credit 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-2/P-3 ratings by S&P's and Moody's. In addition, downgrades in PSE's debt ratings may prompt counterparties to require PSE to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee or provide other security.

On January 16, 2009, S&P's Rating Services raised its corporate credit rating on PSE and removed it from its watch list for negative implications citing a stable outlook. The rating actions reflected the anticipated completion of the acquisition of Puget Energy and PSE by Puget Holdings, which occurred on February 6, 2009.

On February 2, 2009, Moody's affirmed the long-term ratings of PSE. The ratings outlook for PSE is stable.

The ratings of PSE, as of April 27, 2009, were as follows:

	Ratings	
	<u>S&P¹</u>	<u>Moody's²</u>
Puget Sound Energy		
Corporate credit/issuer rating	BBB	Baa3
Senior secured debt	A-	Baa2
Junior subordinated notes	BB+	Ba1
Preferred stock	BB+	Ba2
Commercial paper	A-2	P-3
Bank facilities	BBB	Baa3
Ratings outlook	Stable	Stable

¹ On January 16, 2009, S&P's upgraded PSE's corporate and other credit ratings. It also removed all the ratings from negative watch, citing a stable outlook.

² On February 2, 2009, Moody's affirmed the long-term ratings of PSE.

Other

REGULATION AND RATES

On April 17, 2009, the Washington Commission issued a final order approving and adopting a settlement agreement that authorized PSE to defer certain ownership and operating costs related to its purchase of the Mint Farm that will be incurred prior to PSE recovering such costs in electric customer rates. Under Washington state law, a company may defer the costs associated with purchasing and operating a gas plant that complies with the greenhouse gases (GHG) emissions performance standard until the plant is included in rates or for two years from the date of purchase, whichever is sooner. As of March 31, 2009, PSE had established a regulatory asset of \$7.7 million. The prudence of the Mint Farm acquisition, recovery of costs of Mint Farm and compliance with the GHG emissions performance standard will be addressed in the Company's next rate proceeding.

On October 8, 2008, the Washington Commission issued its order in PSE's consolidated electric and natural gas general rate case filed in December 2007, approving a general rate increase for electric customers of \$130.2 million or 7.1% annually, and an increase in natural gas rates of \$49.2 million or 4.6% annually. The rate increases for electric and natural gas customers were effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25% and a capital structure that included 46.0% common equity with a return on equity of 10.15%. The Washington Commission issued a separate order on January 15, 2009, that authorized the continuation of the Power Cost Only Rate Case (PCORC) with certain modifications to which the Washington Commission staff and the Company had agreed. The five procedural modifications to the PCORC include extending the expected procedural schedule from five to six months, limiting the power cost updates to one per PCORC unless an additional update is allowed by the Washington Commission as part of the compliance filing, prohibiting the overlap of PCORC and general rate cases (except for requests for interim rate relief), shortening data request time from ten to five business days and requiring the Company to provide its future energy resource model projections at the outset of a case.

On September 25, 2008, the Washington Commission approved PSE's requested revisions to its PGA tariff schedules resulting in an increase of \$108.8 million or 11.1% on an annual basis in gas sales revenues effective October 1, 2008. The rate increase was the result of higher costs of natural gas in the forward market and a reduction of the credit for the accumulated PGA payable balance. The PGA rate change will increase PSE's revenue but will not impact the Company's net income as the increased revenue will be offset by increased purchased gas costs.

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, 2008 includes a summary relating to the western power market proceedings. PSE is vigorously defending each of these cases. Litigation is subject to numerous uncertainties and PSE is unable to predict the ultimate outcome of these matters. Accordingly, there can be no

guarantee that these proceedings, either individually or in the aggregate, will not materially and/or adversely affect PSE's financial condition, results of operations or liquidity.

CPUC v. FERC. On August 2, 2006, the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit) decided that FERC erred in excluding potential relief for tariff violations for periods that pre-dated October 2, 2000 and additionally ruled that FERC should consider remedies for transactions previously considered outside the scope of the proceedings. The August 2, 2006 decision may adversely impact PSE's ability to recover the full amount of its California Independent System Operator (CAISO) receivable. The decision may also expose PSE to claims or liabilities for transactions outside the previously defined "refund period." At this time, the ultimate financial outcome for PSE is unclear. Rehearing by the Ninth Circuit was denied on April 6, 2009. Parties have been engaged in court-sponsored settlement discussions, and those discussions may result in some settlements. PSE is unable to predict either the outcome of the proceedings or the ultimate financial effect on PSE.

PROCEEDINGS RELATING TO THE BONNEVILLE POWER ADMINISTRATION

Petitioners in several actions in the Ninth Circuit against BPA asserted that BPA acted contrary to law in entering into or performing or implementing a number of agreements, including the amended settlement agreement (and the May 2004 agreement) between BPA and PSE regarding the REP. Petitioners in several actions in the Ninth Circuit against BPA also asserted that BPA acted contrary to law in adopting or implementing the rates upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period were based. A number of parties claimed that the BPA rates proposed or adopted in the BPA rate proceeding to develop BPA rates to be used in the agreements for determining the amounts of money to be paid to PSE by BPA during the period October 1, 2006 through September 30, 2009 are contrary to law and that BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing or implementing such agreements.

On May 3, 2007, the Ninth Circuit issued an opinion in *Portland Gen. Elec. v. BPA*, Case No. 01-70003, in which proceeding the actions of BPA in entering into settlement agreements regarding the REP with PSE and with other investor-owned utilities were challenged. In this opinion, the Ninth Circuit granted petitions for review and held the settlement agreements entered into between BPA and the investor-owned utilities being challenged in that proceeding to be inconsistent with statute. On May 3, 2007, the Ninth Circuit also issued an opinion in *Golden Northwest Aluminum v. BPA*, Case No. 03-73426, in which proceeding the petitioners sought review of BPA's 2002-2006 power rates. In this opinion, the Ninth Circuit granted petitions for review and held that BPA unlawfully shifted onto its preference customers the costs of its settlements with the investor-owned utilities. On October 5, 2007, petitions for rehearing of these two opinions were denied. On February 1, 2008, PSE and other utilities filed in the Supreme Court of the United States a petition for a writ of certiorari to review the decisions of the Ninth Circuit, which petition was denied in June 2008.

In May 2007, following the Ninth Circuit's issuance of these two opinions, BPA suspended payments to PSE under the amended settlement agreement (and the May 2004 agreement). On October 11, 2007, the Ninth Circuit remanded the May 2004 agreement to BPA in light of the *Portland Gen. Elec. v. BPA* opinion and dismissed the remaining three pending cases regarding settlement agreements.

In March 2008, BPA and PSE signed an agreement pursuant to which BPA made a payment to PSE related to the REP benefits for the fiscal year ended September 30, 2008, which payment is subject to true-up depending upon the amount of any REP benefits ultimately determined to be payable to PSE. In March and April 2008, Clatskanie People's Utility District filed petitions in the Ninth Circuit for review of BPA actions in connection with offering or entering into such agreement with PSE and similar agreements with other investor-owned utilities. Clatskanie People's Utility District asserts that BPA's actions in entering into and executing the 2008 REP agreements were contrary to law or without authority and that such agreements are null and void and result in overpayments of REP benefits to PSE and other regional investor-owned utilities.

In September 2008, BPA issued its record of decision in its reopened WP-07 rate proceeding to respond to the various Ninth Circuit opinions. In this record of decision, BPA adjusted its fiscal year 2009 rates, determined the amounts of REP benefits it considered to have been improperly paid after fiscal year 2001 to PSE and the other regional investor-owned utilities, and determined that such amounts are to be recovered through reductions in REP benefit payments to be made over a number of years. The amount determined by BPA to be recovered through reductions commencing October 2007 in REP payments for PSE's residential and small farm customers was approximately \$207.2 million plus interest on unrecovered amounts. However, these BPA determinations are subject to subsequent administrative and judicial review, which may alter

or reverse such determinations. PSE and others, including a number of preference agency and investor-owned utility customers of BPA, in December 2008 filed petitions for review in the Ninth Circuit of various of these BPA determinations. PSE is reviewing its options in determining if it will contest the amounts withheld as improper payments made since 2001.

In September 2008, BPA and PSE signed a short-term Residential Purchase and Sale Agreement (RPSA) under which BPA is to pay REP benefits to PSE for fiscal years ending September 30, 2009–2011. In December 2008, BPA and PSE signed another long-term RPSA under which BPA is to pay REP benefits to PSE for the period October 2011 through September 2028. PSE and other customers of BPA in December 2008 filed petitions for review in the Ninth Circuit of the short-term and long-term RPSAs signed by PSE (and similar RPSAs signed by other investor-owned utility customers of BPA) and BPA's record of decision regarding such RPSAs. Generally, REP benefit payments under a RPSA are based on the amount, if any, by which a utility's average system cost (ASC) exceeds BPA's Priority Firm (PF) Exchange rate for such utility. The ASC for a utility is determined using an ASC methodology adopted by BPA. The ASC methodology adopted by BPA and the ASC determinations, REP overpayment determinations, and the PF Exchange rate determinations by BPA are all subject to FERC review or judicial review or both and are subject to adjustment, which may affect the amount of REP benefits paid or to be paid by BPA to PSE. As discussed above, BPA has determined to reduce such payments based on its determination of REP benefit overpayments after fiscal year 2001.

It is not clear what impact, if any, such development or review of such BPA rates, review of such ASC, ASC methodology, and BPA determination of REP overpayments, review of such agreements, and the above described Ninth Circuit litigation may ultimately have on PSE.

NEW ACCOUNTING PRONOUNCEMENTS

On April 9, 2009, the Financial Standards Accounting Board (FASB) issued Staff Position (FSP) No. 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP No. 157-4). FSP No. 157-4 provides additional guidance for estimating fair value in accordance with Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" (SFAS No. 157), when the volume and level of activity for the asset or liability have significantly decreased. FSP No. 157-4 also includes guidance on identifying circumstances that indicate a transaction is not orderly. FSP No. 157-4 will be effective for the Company as of June 30, 2009. The Company is currently assessing the impact of the FSP on its SFAS No. 157 calculations and disclosures.

On April 9, 2009, FASB issued FSP No. 107-1, "Interim Disclosures about Fair Value of Financial Instruments" (FSP No. 107-1). FSP No. 107-1 amends SFAS No. 107, Disclosures about Fair Value of Financial Instruments, to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. FSP No. 107-1 also amends APB Opinion No. 28, "Interim Financial Reporting," to require those disclosures in summarized financial information at interim reporting periods. FSP No. 107-1 will be effective for the Company as of June 30, 2009.

Item 3. **Quantitative and Qualitative Disclosure About Market Risk**

ENERGY PORTFOLIO MANAGEMENT

The Company maintains energy risk policies and procedures to manage commodity and volatility risks and the related effects on credit, tax, accounting, financing and liquidity. The Company's Energy Management Committee establishes the Company's risk management policies and procedures, and monitors compliance. The Energy Management Committee is comprised of certain Company officers and is overseen by the Board of Directors.

The Company is focused on commodity price exposure and risks associated with volumetric variability in the gas and electric portfolios and the related effects noted above. It is not engaged in the business of assuming risk for the purpose of speculative trading. The Company hedges open gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 250 simulations of how the Company's gas and power portfolios will perform under various weather, hydro and unit performance conditions. The objectives of the hedging strategy are to:

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

The following table presents electric derivatives that do not meet the Normal Purchase Normal Sale (NPNS) exception at March 31, 2009 and December 31, 2008 including contracts designated as cash flow hedges:

(DOLLARS IN MILLIONS)	ELECTRIC DERIVATIVES	
	MARCH 31, 2009	DECEMBER 31, 2008
Current asset	\$ 1.3	\$ 0.4
Long-term asset	0.9	0.5
Total assets	\$ 2.2	\$ 0.9
Current liability	\$ 151.9	\$ 90.6
Long-term liability	122.3	96.1
Total liabilities	\$ 274.2	\$ 186.7

If it is determined that it is uneconomical to operate the Company's controlled electric generating facilities in the future period, the fuel supply cash flow hedge relationship is terminated and the hedge is de-designated which results in recognition of future changes in value in the income statements. As these contracts are settled, amounts previously deferred in other comprehensive income (OCI) are recognized as energy costs and are included as part of the Power Cost Adjustment (PCA) mechanism.

The following table presents the impact of changes in the market value of derivative instruments not meeting NPNS or cash flow hedge criteria to the Company's earnings for the three months ended March 31, 2009 and March 31, 2008:

(DOLLARS IN MILLIONS)	MARCH 31, 2009	MARCH 31, 2008	CHANGE
Decrease in earnings	\$ (2.3)	\$ (0.1)	\$ (2.2)

The decrease in earnings in 2009 primarily relates to a \$3.2 million unrealized loss associated with the ineffective portion of cash flow hedges for two long-term power supply agreements.

The amount of unrealized gain (loss), net of tax, related to the Company's energy-related cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), deferred in accumulated OCI consisted of the following at March 31, 2009 and December 31, 2008:

	MARCH 31, 2009	DECEMBER 31, 2008
(DOLLARS IN MILLIONS, NET OF TAX)		
Other comprehensive income – unrealized loss	\$ (166.3)	\$ (111.7)

The following table presents natural gas derivative contracts at March 31, 2009 and December 31, 2008:

	GAS DERIVATIVES	
	MARCH 31, 2009	DECEMBER 31, 2008
(DOLLARS IN MILLIONS)		
Current asset	\$ 20.9	\$ 15.2
Long-term asset	9.3	6.2
Total assets	\$ 30.2	\$ 21.4
Current liability	\$ 172.4	\$ 146.3
Long-term liability	54.4	62.3
Total liabilities	\$ 226.8	\$ 208.6

At March 31, 2009, the Company had total assets of \$30.2 million and total liabilities of \$226.8 million related to financial contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers. All fair value adjustments on derivatives relating to the natural gas business have been reclassified to a deferred account in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), due to the PGA mechanism. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism. As the gains and losses on the hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism.

A hypothetical 10.0% decrease in market prices of natural gas and electricity would decrease the fair value of derivative contracts by \$93.6 million, with a corresponding after-tax decrease in OCI and earnings of \$33.3 million and \$2.3 million, respectively, after-tax, and would decrease the fair value of those contracts marked-to-market in earnings by \$1.6 million after-tax. A discussion of the Level 3 valuation is included in Note 4, "Fair Value Measurements."

CONTINGENT FEATURES AND COUNTERPARTY CREDIT RISK

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

Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate the potential credit default losses. Criteria employed in this decision includes, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure. As of March 31, 2009, the Company held approximately \$1.1 million worth of standby letters of credit in support of various electricity and renewable energy credit transactions.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of March 31, 2009, approximately 99.6% of the counterparties with transaction amounts outstanding in the Company's energy portfolio, including NPNS transactions, are rated at least investment grade by the major rating agencies and 0.4% are either rated below investment grade or are not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

The Company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The Company generally enters into the following master arrangements: (1) Western Systems Power Pool agreements (WSPP) - standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) - standardized financial gas and electric contracts; and (3) North American Energy Standards Board agreements (NAESB) - standardized physical gas contracts. The Company believes that entering into such agreements reduces the risk of default by allowing a counterparty the ability to make only one net payment.

The Company monitors counterparties that are experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies, or have changes in ownership. Counterparty credit risk impacts the Company's decisions on derivative accounting treatment. A counterparty may have a deterioration of credit below investment grade, potentially indicating that it is no longer probable that it will fulfill its obligations under a contract (e.g., make a physical delivery upon the contract's maturity). SFAS No. 133 specifies the requirements for derivative contracts to qualify for the NPNS scope exception. When performance is no longer probable, based on the deterioration of a counterparty's credit, the Company records the fair value of the contract on the balance sheet, with the corresponding amount recorded in the income statement.

Cash flow hedge derivative treatment is also impacted by a counterparty's deterioration of credit under SFAS No. 133 guidelines. If a forecasted transaction associated with a cash flow hedge is no longer probable of occurring, based on deterioration of credit, the Company would discontinue hedge accounting, record in earnings subsequent changes in the derivative's fair value and freeze amounts previously accounted for in Accumulated Other Comprehensive Income. If the transaction is remote of occurring, any amounts previously accounted for in Accumulated Other Comprehensive Income would be reclassified into earnings.

Should a counterparty file for bankruptcy, which could be considered a default under master arrangements, the Company may terminate related contracts. Derivative accounting entries previously recorded would be reversed in financial statements. The Company would compute any termination receivable or payables, based on the terms of existing master arrangements.

The Company computes credit reserves at a master agreement level (i.e. WSPP, ISDA or NAESB) by counterparty. The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by S&P and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is used by weighting fair values and contract tenors for all deals for each counterparty and coming up with an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. Moreover, the Company applies its own default factor to compute credit reserves for counterparties in a net liability position. The Company's S&P rating at March 31, 2009 was BBB. Credit reserves are booked as contra accounts to unrealized gain (loss) positions. As of March 31, 2009, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the year.

INTEREST RATE RISK

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, variable-rate notes and leases and anticipated long-term debt financing needed to fund capital requirements. The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company utilizes bank borrowings, commercial paper and line of credit facilities to meet short-term cash requirements. These short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts. The Company did not have any swap instruments outstanding as of March 31, 2009; however from time to time the Company may enter into treasury lock or forward starting swap contracts to hedge interest rate exposure related to an anticipated debt issuance. The ending balance in other comprehensive income related to the forward starting swaps and previously settled treasury lock contracts at March 31, 2009 is a net loss of \$7.8 million after tax and accumulated amortization. This compares to a loss of \$7.9 million in other comprehensive income after-tax and accumulated amortization

at December 31, 2008. All financial hedge contracts of this type are reviewed by senior management and presented to the Securities Pricing Committee of the Board of Directors and are approved prior to execution.

Item 4. **Controls and Procedures**

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 the Executive Vice President and Chief Financial Officer, PSE has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of March 31, 2009, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer of PSE concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in PSE's internal control over financial reporting during the quarter ended March 31, 2009, that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. **Legal Proceedings**

See the section titled "Proceedings Relating to the Western Power Market" under "Other" of Management's Discussion and Analysis of Financial Conditions and Results of Operations of this Report on Form 10-Q. Contingencies arising out of the normal course of the Company's business exist at March 31, 2009. Litigation is subject to numerous uncertainties and PSE is unable to predict the ultimate outcome of these matters.

Item 1A. **Risk Factors**

There have been no material changes from the risk factors set forth in Part I, Item 1A in the Company's Annual Report on Form 10-K for the year ended December 31, 2008.

Item 6. **Exhibits**

See Exhibit Index for list of exhibits.

SIGNATURES

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

PUGET SOUND ENERGY, INC.

/s/ James W. Eldredge

James W. Eldredge

Vice President, Controller and Chief

Accounting Officer

Date: May 5, 2009

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

EXHIBIT INDEX

- 4.1** Fortieth through Sixtieth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to Exhibits 4.3 through 4.23 to PSE's Registration Statement on Form S-3, dated March 13, 2009, Commission File No. 333-157960).
- 4.2** Indenture of First Mortgage, dated as of April 1, 1957, defining the rights of the holders of Puget Sound Energy's Gas Utility First Mortgage Bonds (incorporated herein by reference to Exhibit 4.25 to PSE's Registration Statement on Form S-3, dated March 13, 2009, Commission File No. 333-157960).
- 4.3** First, Sixth, Seventh, Sixteenth and Seventeenth Supplemental Indenture to the Gas Utility First Mortgage (incorporated herein by reference to Exhibits 4.26 through 4.30 to PSE's Registration Statement on Form S-3, dated March 13, 2009, Commission File No. 333-157960).
- 10.1* First Amendment dated as of October 4, 1961 to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project.
- 10.2* First Amendment dated February 9, 1965 to Power Sales Contract between Public Utility District No. 1 of Douglas County, Washington and Puget Sound Energy, Inc., relating to the Wells Development.
- 10.3* Contract dated November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project.
- 10.4* Power Sales Contract dated as of November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and Puget Sound Energy, Inc., relating to the Rocky Reach Project.
- 10.5* Power Sales Contract dated May 21, 1956 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Priest Rapids Project.
- 10.6* First Amendment to Power Sales Contract dated as of August 5, 1958 between Puget Sound Energy, Inc. and Public Utility District No. 2 of Grant County, Washington, relating to the Priest Rapids Development.
- 10.7* Power Sales Contract dated June 22, 1959 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Wanapum Development.
- 10.8* Agreement to Amend Power Sales Contracts dated July 30, 1963 between Public Utility District No. 2 of Grant County, Washington and Puget Sound Energy, Inc., relating to the Wanapum Development.
- 10.9* Power Sales Contract executed as of September 18, 1963 between Public Utility District No. 1 of Douglas County, Washington and Puget Sound Energy, Inc., relating to the Wells Development.
- 10.10* Construction and Ownership Agreement dated as of July 30, 1971 between The Montana Power Company and Puget Sound Energy, Inc.

- 10.11* Operation and Maintenance Agreement dated as of July 30, 1971 between The Montana Power Company and Puget Sound Energy, Inc.
- 10.12* Contract dated June 19, 1974 between Puget Sound Energy, Inc. and P.U.D. No. 1 of Chelan County.
- 10.13+ Form of Executive Employment Agreement between Puget Sound Energy, Inc. and each of Eric M. Markell, Kimberly J. Harris, Jennifer L. O'Connor, James W. Eldredge, Donald E. Gaines and Bertrand A. Valdman (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K dated April 3, 2009).
- 12.1* Statement setting forth computation of ratios of earnings to fixed charges (2004 through 2008 and 12 months ended March 31, 2009) for PSE.
- 31.1* 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.
- 31.2* 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.

* Filed herewith.

** Previously filed with a report or registration statement that is more than 30 years old and therefore refiled with, or incorporated by reference into, this report.

+ Management contract or compensating plan or arrangement.