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

Form 10-Q

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

For the quarterly period ended June 30, 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 No. 1-15973

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon	93-0256722
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (503) 226-4211

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 Web site, 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 [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [X]

At July 31, 2009, 26,513,188 shares of the registrant’s Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended June 30, 2009

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

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Forward-Looking Statements

Statements and information included in this report that are not purely historical are forward-looking statements within the “safe harbor” provisions and meaning of Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). Forward-looking statements include any statement other than a statement of purely historical fact, but are not limited to, statements concerning plans, objectives, goals, business and financial strategies, future events or performance or operational efficiencies, trends, cyclicality and the seasonality of our business, growth, capitalization, company ratings, development of projects, future cost of gas or our ability to manage such costs, customer rates, gains or losses from our share of gas costs that are less than or more than the gas costs embedded in customer rates, acquisition of new gas supplies, workforce levels, cost reduction efforts, estimated expenditures, budgets, capital and construction costs, and future cash flows, costs of compliance, impact of accounting policies and standards, potential efficiencies, impacts of new laws and regulations, projected obligations and liabilities under retirement plans, adequacy of and shift in mix of gas supplies, and adequacy of accruals and regulatory deferrals. Such statements are expressed in good faith and we believe have a reasonable basis; however, each forward-looking statement involves uncertainties and is qualified in its entirety by reference to the following important factors, among others, that could cause our actual results to differ materially from those projected, including:

- prevailing state and federal governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, timely and adequate regulatory recovery of deferred costs, including, but not limited to, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in laws and regulations including but not limited to tax laws and policies, changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity, including regulatory allowance or disallowance of costs based on regulatory prudency reviews;
- economic factors that could cause a severe downturn in the economy, in particular the economies of Oregon and Washington, thus affecting demand for natural gas;
- unanticipated customer growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;
- the creditworthiness of customers, suppliers and financial derivative counterparties;
- market conditions and pricing of natural gas relative to other energy sources;
- sufficiency of our liquidity position and unanticipated changes that may affect our liquidity or access to capital markets, including volatility in the credit markets and financial services sector;
- capital market conditions, including their effect on financing costs, the fair value of pension assets and pension and other postretirement benefit costs;
- application of the Oregon Public Utility Commission rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;
- weather conditions, natural phenomena including earthquakes or other geohazard events, and other pandemic events;
- competition for retail and wholesale customers and our ability to remain price competitive;

- our ability to access sufficient gas supplies and our dependence on a single pipeline transportation company for natural gas transmission;
- property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;

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- financial and operational risks, estimates and projections relating to business development and investment activities, including the Gill Ranch underground gas storage facility and Palomar pipeline;
- unanticipated changes in interest rates, foreign currency exchange rates or in rates of inflation;
- changes in estimates of potential liabilities relating to environmental contingencies or in timely and adequate regulatory or insurance recovery for such liabilities;
- unanticipated changes in future liabilities and legislation relating to employee benefit plans, including changes in key assumptions;
- our ability to transfer knowledge of our aging workforce and maintain a satisfactory relationship with the union that represents a majority of our workers;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions and the timing of such projects;
- federal, state or other regulatory actions related to climate change; and
- legal and administrative proceedings and settlements.

These forward-looking statements involve risks and uncertainties. We may make other forward-looking statements from time to time, including statements in press releases and public conference calls and webcasts. All forward-looking statements made by us are based on information available to us at the time the statements are made and speak only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for us to predict all such factors, nor can we assess the impact of each such factor 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. Some of these risks and uncertainties are discussed in our 2008 Annual Report on Form 10-K, Part I, Item 1A., "Risk Factors" and Part II, Item 7. and Item 7A., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk," respectively.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Statements of Income
(Unaudited)

Thousands, except per share amounts	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating revenues:				
Gross operating revenues	$ 149,060	$ 191,254	$ 586,415	$ 578,948
Less: Cost of sales	79,388	124,010	363,562	369,930
Revenue taxes	3,753	4,672	14,295	14,023
Net operating revenues	65,919	62,572	208,558	194,995
Operating expenses:				
Operations and maintenance	30,171	25,840	64,126	54,298
General taxes	6,572	6,722	15,063	14,856
Depreciation and amortization	15,365	17,957	30,887	35,662
Total operating expenses	52,108	50,519	110,076	104,816
Income from operations	13,811	12,053	98,482	90,179
Other income and expense - net	732	1,940	1,622	2,113
Interest charges - net of amounts capitalized	10,006	8,933	19,376	18,363
Income before income taxes	4,537	5,060	80,728	73,929
Income tax expense	1,451	1,763	30,279	27,464
Net income	$ 3,086	$ 3,297	$ 50,449	$ 46,465
Average common shares outstanding:				
Basic	26,506	26,421	26,504	26,415
Diluted	26,607	26,571	26,603	26,564
Earnings per share of common stock:				
Basic	$ 0.12	$ 0.12	$ 1.90	$ 1.76
Diluted	$ 0.12	$ 0.12	$ 1.90	$ 1.75

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Balance Sheets
(Unaudited)

Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008
Assets:			
Plant and property:			
Utility plant	$ 2,178,629	$ 2,091,092	$ 2,142,988
Less accumulated depreciation	670,128	637,680	659,123
Utility plant - net	1,508,501	1,453,412	1,483,865
Non-utility property	84,696	72,242	74,506
Less accumulated depreciation	9,849	8,537	9,314
Non-utility property - net	74,847	63,705	65,192
Total plant and property	1,583,348	1,517,117	1,549,057
Current assets:			
Cash and cash equivalents	31,107	5,242	6,916
Accounts receivable	26,779	43,718	81,288
Accrued unbilled revenue	18,122	19,685	102,688
Allowance for uncollectible accounts	(3,520)	(3,013)	(2,927)
Regulatory assets	89,179	5,748	147,319
Fair value of non-trading derivatives	5,293	54,867	4,592
Inventories:			
Gas	69,183	32,910	86,134
Materials and supplies	9,681	9,959	9,933
Income taxes receivable	-	-	20,811
Prepayments and other current assets	26,588	11,516	24,216
Total current assets	272,412	180,632	480,970
Investments, deferred charges and other assets:			
Regulatory assets	270,044	173,321	288,470
Fair value of non-trading derivatives	289	9,218	146
Other investments	62,315	64,276	54,132
Other	16,103	11,417	5,377
Total investments, deferred charges and other assets	348,751	258,232	348,125
Total assets	$ 2,204,511	$ 1,955,981	$ 2,378,152

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Balance Sheets
(Unaudited)

Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 336,001	$ 333,619	$ 336,754
Earnings invested in the business	325,506	293,313	296,005
Accumulated other comprehensive income (loss)	(4,260)	(2,483)	(4,386)
Total common stock equity	657,247	624,449	628,373
Long-term debt	587,000	512,000	512,000
Total capitalization	1,244,247	1,136,449	1,140,373
Current liabilities:			
Notes payable	90,610	67,700	248,000
Long-term debt due within one year	-	5,000	-
Accounts payable	50,055	75,786	94,422
Taxes accrued	10,807	8,727	12,455
Interest accrued	3,876	2,837	2,785
Regulatory liabilities	30,789	84,370	20,456
Fair value of non-trading derivatives	70,052	2,792	136,735
Other current and accrued liabilities	33,343	32,251	36,467
Total current liabilities	289,532	279,463	551,320
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	273,384	221,266	257,831
Regulatory liabilities	238,264	227,076	228,157
Pension and other postretirement benefit liabilities	116,844	43,513	138,229
Fair value of non-trading derivatives	8,844	2,732	21,646
Other	33,396	45,482	40,596
Total deferred credits and other liabilities	670,732	540,069	686,459
Commitments and contingencies (see Note 11)	-	-	-
Total capitalization and liabilities	$ 2,204,511	$ 1,955,981	$ 2,378,152

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30,	
Thousands	2009	2008
Operating activities:		
Net income	$ 50,449	$ 46,465
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	30,887	35,662
Deferred income taxes and investment tax credits	15,405	14,028
Undistributed gains from equity investments	(734)	(346)
Deferred gas savings - net	15,616	(26,873)
Gain on sale of non-utility investments	-	(1,737)
Non-cash expenses related to qualified defined benefit pension plans	4,848	1,530
Contributions to qualified defined benefit pension plans	(25,000)	-
Deferred environmental costs	(5,227)	(4,131)
Income from life insurance investments	(2,002)	(978)
Settlement of interest rate hedge	(10,096)	-
Deferred regulatory and other	(14,123)	(6,466)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	141,173	84,224
Inventories of gas, materials and supplies	17,203	37,075
Income taxes receivable	20,811	-
Prepayments and other current assets	8,428	7,083
Accounts payable	(44,177)	(45,684)
Accrued interest and taxes	(557)	(4,400)
Other current and accrued liabilities	(3,091)	2,634
Cash provided by operating activities	199,813	138,086
Investing activities:		
Investment in utility plant	(44,098)	(41,338)
Investment in non-utility property	(10,330)	(5,110)
Proceeds from sale of non-utility investments	-	6,845
Proceeds from life insurance	761	208
Other	(4,977)	(7,286)
Cash used in investing activities	(58,644)	(46,681)
Financing activities:		
Common stock issued (purchased) - net	(720)	2,589
Long-term debt issued	75,000	-
Change in short-term debt	(170,241)	(75,400)
Cash dividend payments on common stock	(20,937)	(19,808)
Other	(80)	349
Cash used in financing activities	(116,978)	(92,270)

Increase (decrease) in cash and cash equivalents		24,191		(865)
Cash and cash equivalents - beginning of period		6,916		6,107
Cash and cash equivalents - end of period	$	31,107	$	5,242
Supplemental disclosure of cash flow information:				
Interest paid	$	17,828	$	18,424
Income taxes paid	$	1,500	$	14,800

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Notes to Consolidated Financial Statements
(Unaudited)

1. Basis of Financial Statements and Accounting Policies

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), which consist of our regulated gas distribution business, our regulated gas storage businesses, which include our wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), and other investments and business activities, which include our wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and an equity investment in a proposed natural gas transmission pipeline (Palomar) (see Note 2).

In this report, the term "utility" is used to describe the gas distribution business and the term "non-utility" is used to describe the gas storage businesses and other non-utility investments and business activities. Intercompany accounts and transactions have been eliminated, except for transactions required by regulatory accounting not to be eliminated under Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation."

The information presented in the interim consolidated financial statements is unaudited, but includes all material adjustments, including normal recurring accruals, that management considers necessary for a fair statement of the results for each period reported. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2008 Annual Report on Form 10-K (2008 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

Investments in corporate joint ventures and partnerships in which our ownership interest is 50 percent or less and over which we do not exercise control are accounted for by the equity method or the cost method.

Our accounting policies are described in Note 1 of the 2008 Form 10-K. There were no significant changes to those accounting policies during the three and six months ended June 30, 2009. See below for a further discussion of newly adopted standards and recent accounting pronouncements.

Newly Adopted Standards

Business Combinations. Effective January 1, 2009, we adopted SFAS No. 141R, "Business Combinations." This statement amends the principles and requirements for how an acquiror accounts for and discloses its business combinations. The adoption of SFAS No. 141R did not have a material effect on our financial condition, results of operations or cash flows.

Noncontrolling Interests. Effective January 1, 2009, we adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements." This statement amends the reporting requirements of Accounting Research Bulletin No. 51 for noncontrolling interests in subsidiaries to improve the relevance, comparability and transparency of the financial information disclosed. The adoption of SFAS No. 160 did not have a material effect on our financial condition, results of operations or cash flows.

Derivative Instruments and Hedging Activities. Effective January 1, 2009, we adopted SFAS No. 161, "Disclosures About Derivative Instruments and Hedging Activities--an Amendment of FASB Statement No. 133," which requires enhanced disclosures of derivative instruments and hedging activities. SFAS No. 161 expands disclosures by adding qualitative disclosures about our hedging objectives and strategies, fair value gains and losses, and credit-risk-related contingent features in derivative agreements. The disclosures are intended to provide an enhanced understanding of:

- how and why we use derivative instruments;
- how derivative instruments and related hedge items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and its related interpretations; and
- how derivative instruments and related hedged items affect our financial condition, results of operations and cash flows.

The adoption and implementation of this statement did not have, and is not expected to have a material effect on our financial statement disclosures. The required disclosures are included in Note 10, below.

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Determining Whether Share-Based Payment Transactions are Participating Securities. Effective January 1, 2009, we adopted Financial Accounting Standards Board (FASB) Staff Position (FSP) No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities." This statement requires nonforfeitable rights to dividends or dividend equivalents on unvested share-awards to be included in the computation of earnings per share under the two-class method. The adoption of FSP No. EITF 03-6-1 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flows.

Interim Disclosures about Financial Instruments. Effective for periods ending after June 15, 2009, we adopted FSP SFAS No. 107-1 and Accounting Principles Board (APB) Opinion No. 28-1, "Interim Disclosures about Fair Value of Financial Instruments." This statement requires disclosures about the fair value of financial instruments to be made in interim reporting periods where summarized financial information is issued. The adoption of this statement did not have a material effect on our disclosures. See Note 5 and Note 10, below.

Fair Value Considerations. Effective for periods ending after June 15, 2009, we adopted FSP SFAS 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." This pronouncement provides an outline and required disclosures, if necessary, to determine if the market for measuring our financial instruments has significantly decreased in volume and level of activity. The adoption of this statement did not have a material effect on our financial statement disclosures.

Subsequent Events. Effective June 15, 2009, we adopted SFAS No. 165, "Subsequent Events." This statement establishes principles and disclosure requirements for events or transactions that occur after the balance sheet date but before the financial statements are issued. As of August 6, 2009, we have evaluated events subsequent to the balance sheet date. For subsequent event footnote, see Note 12.

Recent Accounting Pronouncements

Pensions. In December 2008, the FASB issued SFAS No. 132R-1, "Employers' Disclosures about Pensions and Other Postretirement Benefits," which requires enhanced disclosures of plan assets in an employer's defined benefit pension or other postretirement benefit plans. SFAS No. 132R-1 is effective for reporting periods ending after December 15, 2009. The disclosures are intended to provide an enhanced understanding of:

- how investment allocation decisions are made;
- the major categories of plan assets;
- the inputs and valuation techniques used to measure the fair value of plan assets;
- the effect of fair value measurements using significant unobservable inputs (Level 3 input from SFAS No. 157, "Fair Value Measurements") on changes in plan assets for the period; and
- significant concentration or risk within plan assets.

The adoption of SFAS No. 132R-1 is not expected to have a material effect on our financial statement disclosures.

Variable Interest Entity. In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)." This pronouncement amends FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities," and requires an analysis to determine whether our variable interest provides us with a controlling financial interest in the variable interest entity. It defines the primary beneficiary of the variable interest entity as the entity having:

- power to control the activities that most significantly impact the performance; and
- the obligation to absorb losses or right to receive benefits from the entity that could potentially be significant to the variable interest entity.

SFAS No. 167 is effective for the first annual reporting period that begins after November 15, 2009. We are evaluating the impact the adoption of SFAS No. 167 will have on our investments in variable interest entities. If consolidated, our variable interest entities could have a material impact on our balance sheet, but it is not expected to materially impact our results of operations or cash flows.

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2. Segment Information

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to either of these two reporting segments which we aggregate and report as "other." We refer to our local gas distribution business as the "utility," and our "gas storage" and "other" business segments as "non-utility." Our gas storage segment includes Gill Ranch in California and a portion of the Mist underground storage facility in Oregon, and our "other" segment includes an equity investment in Palomar and Financial Corporation.

The following tables present information about the reportable segments for the three and six months ended June 30, 2009 and 2008. Inter-segment transactions are insignificant.

	Three Months Ended June 30,			
Thousands	Utility	Gas Storage	Other	Total
2009				
Net operating revenues	$ 60,066	$ 5,825	$ 28	$ 65,919
Depreciation and amortization	15,029	336	-	15,365
Income from operations	8,955	4,852	4	13,811
Net income (loss)	439	2,734	(87)	3,086
2008				
Net operating revenues	$ 57,183	$ 5,339	$ 50	$ 62,572
Depreciation and amortization	17,633	324	-	17,957
Income (loss) from operations	7,451	4,907	(305)	12,053
Net income (loss)	(743)	2,488	1,552	3,297

	Six Months Ended June 30,			
Thousands	Utility	Gas Storage	Other	Total
2009				
Net operating revenues	$ 198,160	$ 10,325	$ 73	$ 208,558
Depreciation and amortization	30,212	675	-	30,887
Income from operations	89,849	8,597	36	98,482
Net income (loss)	45,743	4,766	(60)	50,449
Total assets at June 30, 2009	2,092,788	96,711	15,012	2,204,511
2008				
Net operating revenues	$ 184,562	$ 10,336	$ 97	$ 194,995
Depreciation and amortization	35,012	650	-	35,662
Income from operations	81,328	8,750	101	90,179
Net income	39,799	4,841	1,825	46,465
Total assets at June 30, 2008	1,877,199	67,198	11,584	1,955,981
Total assets at Dec. 31, 2008	2,289,601	72,073	16,478	2,378,152

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Included in total assets at June 30, 2009 and 2008, our major non-utility investments were as follows:

- Mist gas storage (excluding amounts allocated to our utility) was $57.0 million and $53.6 million, respectively;
- Gill Ranch storage was $23.9 million and $7.8 million, respectively;
- Palomar was $10.6 million and $9.3 million, respectively; and
- Financial Corporation was $1.0 million for both periods.

In April 2008, we sold our investment in a Boeing 737-300 aircraft for approximately $6.2 million cash, plus accrued rents. As a result of the sale, we recognized an after-tax gain of $1.1 million in the second quarter of 2008, which was recorded in our other segment.

In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million that expires on September 30, 2009. As of June 30, 2009, Gill Ranch had $10.8 million of borrowings outstanding included under notes payable on the balance sheet, with a corresponding cash collateral included in prepayments and other current assets on the balance sheet. The effective interest rate on Gill Ranch's credit facility is 0.8 percent.

Palomar has precedent agreements whereby a significant majority of the pipeline capacity is committed to one shipper. In April 2009, Palomar and that majority shipper replaced the prior precedent agreement with a new agreement and Palomar received cash proceeds of $15.8 million which had supported the shipper's obligations under the prior agreement. The new agreement is for the same amount of capacity as the prior agreement. Our maximum loss exposure related to Palomar as of June 30, 2009 is limited to our net investment balance of $10.6 million. Our loss exposure would be reduced by any credit support recovered from third parties should they default on current agreements.

3. Capital Stock

As of June 30, 2009, our common shares authorized were 100,000,000 and our outstanding shares were 26,513,188.

We have a common share repurchase program under which we may purchase shares on the open market or through privately negotiated transactions. Since inception of the repurchase program in 2000, the Board has authorized repurchases through May 31, 2010 up to an aggregate 2.8 million shares or $100 million. No shares were repurchased under this program during the six months ended June 30, 2009. To date, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

4. Stock-Based Compensation

Our stock-based compensation plans consist of the Long-Term Incentive Plan (LTIP), the Restated Stock Option Plan (Restated SOP) and the Employee Stock Purchase Plan (ESPP). These plans are designed to promote stock ownership by employees and officers. For additional information on our stock-based compensation plans, see Part II, Item 8., Note 4, in the 2008 Form 10-K and current updates provided below.

Long-Term Incentive Plan. On February 25, 2009, 39,000 performance-based shares were granted under the LTIP based on target-level awards, which include a market condition and a weighted-average grant date fair value of $9.59 per share. Fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following assumptions:

Stock price on valuation date	$41.15
Performance term (in years)	3.0

Quarterly dividends paid per share	$0.395
Expected dividend yield	3.8%
Dividend discount factor	0.8927

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In February 2009, the Board approved a payout of performance-based stock awards for the 2006-08 award period. Shares of common stock were purchased on the open market to satisfy the approved awards.

Restated Stock Option Plan. On February 25, 2009, options to purchase 111,750 shares were granted under the Restated SOP, with an exercise price equal to the closing market price of $41.15 per share on the date of grant, vesting over a four-year period following the date of grant and with a term of 10 years and 7 days. The weighted-average grant date fair value was $5.46 per share. Fair value was estimated as of the date of grant using the Black-Scholes option pricing model based on the following assumptions:

Risk-free interest rate	2.0%
Expected life (in years)	4.7
Expected market price volatility factor	22.5%
Expected dividend yield	3.8%
Forfeiture rate	3.7%

As of June 30, 2009, there was $1.0 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2012. For the six months ended June 30, 2009 and 2008, the expense recognized based on the fair value of stock options was $0.3 million and $0.4 million, respectively.

5. Cost and Fair Value Basis of Long-Term Debt

In March 2009, we issued $75 million of 5.37 percent secured medium-term notes (MTNs) due February 1, 2020. Proceeds from these MTNs were used to redeem short-term debt of the utility and for general corporate purposes, including funding utility capital expenditures and working capital needs. On July 9, 2009, we issued another $50 million of secured MTNs with an interest rate of 3.95 percent and a due date of July 15, 2014. Proceeds from these MTNs will be used to fund utility capital expenditures as well as to redeem short-term debt.

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At June 30, 2009 and 2008 and December 31, 2008, we had outstanding long-term debt as follows:

Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008
Medium-Term Notes			
First Mortgage Bonds:			
6.50 % Series B due 2008(1)	$ -	$ 5,000	$ -
4.11 % Series B due 2010	10,000	10,000	10,000
7.45 % Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	10,000	10,000
7.13 % Series B due 2012	40,000	40,000	40,000
8.26 % Series B due 2014	10,000	10,000	10,000
4.70 % Series B due 2015	40,000	40,000	40,000
5.15 % Series B due 2016	25,000	25,000	25,000
7.00 % Series B due 2017	40,000	40,000	40,000
6.60 % Series B due 2018	22,000	22,000	22,000
8.31 % Series B due 2019	10,000	10,000	10,000
7.63 % Series B due 2019	20,000	20,000	20,000
5.37 % Series B due 2020(2)	75,000	-	-
9.05 % Series A due 2021	10,000	10,000	10,000
5.62 % Series B due 2023	40,000	40,000	40,000
7.72 % Series B due 2025	20,000	20,000	20,000
6.52 % Series B due 2025	10,000	10,000	10,000
7.05 % Series B due 2026	20,000	20,000	20,000
7.00 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2028	10,000	10,000	10,000
7.74 % Series B due 2030	20,000	20,000	20,000
7.85 % Series B due 2030	10,000	10,000	10,000
5.82 % Series B due 2032	30,000	30,000	30,000
5.66 % Series B due 2033	40,000	40,000	40,000
5.25 % Series B due 2035	10,000	10,000	10,000
	587,000	517,000	512,000
Less long-term debt due within one year	-	5,000	-
Total long-term debt	$ 587,000	$ 512,000	$ 512,000

(1) Redeemed at maturity in July 2008.
(2) Issued in March 2009.

The following table provides an estimate of the fair value of our long-term debt as of June 30, 2009 and December 31, 2008, using market prices in effect on the valuation dates. The fair value of our long-term debt issues was estimated using marketable debt securities with similar credit ratings, terms and remaining maturities.

	June 30, 2009		Dec. 31, 2008	
Thousands	Carrying Amount	Estimated Fair Value (1)	Carrying Amount	Estimated Fair Value (1)
Long-term debt including amounts due				

within one year	$	587,000	$	612,931	$	512,000	$	505,828

(1) This estimate is calculated net of commission fees.

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6. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during each period presented. The diluted earnings per share calculation includes common shares outstanding and the potential effects of the assumed exercise of stock options outstanding and estimated stock awards from our other stock-based compensation plans. Diluted earnings per share are calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands, except per share amounts	2009	2008	2009	2008
Net income	$ 3,086	$ 3,297	$ 50,449	$ 46,465
Average common shares outstanding - basic	26,506	26,421	26,504	26,415
Additional shares for stock-based compensation plans	101	150	99	149
Average common shares outstanding - diluted	26,607	26,571	26,603	26,564
Earnings per share of common stock - basic	$ 0.12	$ 0.12	$ 1.90	$ 1.76
Earnings per share of common stock - diluted	$ 0.12	$ 0.12	$ 1.90	$ 1.75

For the three and six months ended June 30, 2009, a total of 6,228 and 5,143 common shares, respectively, were excluded from the calculation of diluted earnings per share because the effect of these additional shares would have been anti-dilutive. For the three and six months ended June 30, 2008, no common share equivalents were excluded from the calculation of diluted earnings per share because all common share equivalents were dilutive.

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7. Pension and Other Postretirement Benefits

The following tables provide the components of net periodic benefit cost for our company-sponsored qualified and non-qualified defined benefit pension plans and other postretirement benefit plans:

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2009	2008	2009	2008
Service cost	$ 1,664	$ 1,653	$ 148	$ 132
Interest cost	4,492	4,303	407	349
Expected return on plan assets	(3,994)	(4,777)	-	-
Amortization of loss	1,658	96	4	-
Amortization of prior service cost	305	313	49	50
Amortization of transition obligation	-	-	103	103
Net periodic benefit cost	4,125	1,588	711	634
Amount allocated to construction	(1,178)	(409)	(232)	(224)
Net amount charged to expense	$ 2,947	$ 1,179	$ 479	$ 410

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2009	2008	2009	2008
Service cost	$ 3,327	$ 3,308	$ 295	$ 265
Interest cost	8,984	8,604	813	698
Expected return on plan assets	(7,989)	(9,554)	-	-
Amortization of loss	3,317	192	8	-
Amortization of prior service cost	611	627	98	99
Amortization of transition obligation	-	-	206	206
Net periodic benefit cost	8,250	3,177	1,420	1,268
Amount allocated to construction	(2,356)	(788)	(464)	(431)
Net amount charged to expense	$ 5,894	$ 2,389	$ 956	$ 837

See Part II, Item 8., Note 7, in the 2008 Form 10-K for more information about our pension and other postretirement benefit plans.

In addition to the company-sponsored defined benefit plans referred to above, we contribute to a multiemployer pension plan for our bargaining unit employees in accordance with our collective bargaining agreement, known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The Western States Plan is managed by a board of trustees that includes equal representation from participating employers and labor unions. Contribution rates are established by collective bargaining agreements and benefit levels are set by the board of trustees based on the advice of an independent actuary regarding the level of benefits that agreed-upon contributions are expected to support. The Western States Plan currently has an accumulated funding deficiency (i.e., a failure to satisfy the minimum funding requirements) for the current plan year and remains in “critical status.” Federal law requires pension plans in critical status to adopt a rehabilitation plan designed to restore the financial health of the plan. Rehabilitation plans may specify benefit reductions, contribution surcharges, or a combination of the two. Our total contribution to the Western States Plan in 2008 amounted to $0.4 million. We made contributions totaling $0.2 million to the Western States Plan for both the six months ended June 30, 2009 and 2008. We expect the Western

States Plan board of trustees to impose a 5 percent surcharge on participating employers, including NW Natural, beginning in 2009 with a 10 percent contribution surcharge for years thereafter. We also expect the trustees to reduced benefit accrual rates and adjustable benefits for active employee participants. These changes are expected as part of a rehabilitation plan to improve funding status of the plan.

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Surcharges above 10 percent may be assessed to employer participants in future years, but these higher surcharges will not go into effect for NW Natural until its next collective bargaining agreement, which is expected to be no earlier than June 1, 2014. Under the terms of our collective bargaining agreement, which became effective July 13, 2009, we can withdraw from the Western States Plan at any time. If we withdraw and the plan is underfunded, we could be assessed a withdrawal liability. We have no current intent to withdraw from the plan, so we have not recorded a withdrawal liability.

Employer Contributions

We make contributions periodically to our single-employer qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. In April 2009, we made an aggregate $25 million cash contribution for the 2008 plan year. In addition, we made cash contributions for our unfunded, non-qualified pension plans and other postretirement benefit plans in the form of ongoing benefit payments of $1.7 million and $1.4 million during the six months ended June 30, 2009 and 2008, respectively. For more information see Part II, Item 8., Note 7, in the 2008 Form 10-K.

8. Comprehensive Income

Items excluded from net income and charged directly to common stock equity are included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in common stock equity is $4.3 million, $2.5 million and $4.4 million at June 30, 2009 and 2008 and December 31, 2008, respectively, which is related to employee benefit plan liabilities and unrealized gains or losses from derivatives not included under regulatory assets and liabilities (see Note 10, below). The following table provides a reconciliation of net income to total comprehensive income for the three and six months ended June 30, 2009 and 2008.

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	2009	2008	2009	2008
Net income	$ 3,086	$ 3,297	$ 50,449	$ 46,465
Amortization of employee benefit plan liability, net of tax	63	55	126	110
Change in unrealized loss from derivatives, net of tax	-	304	-	908
Total comprehensive income	$ 3,149	$ 3,656	$ 50,575	$ 47,483

9. Fair Value of Financial Instruments

We use fair value measurements to record adjustments to certain financial instruments and to determine fair value disclosures. As of June 30, 2009 and 2008 and December 31, 2008, we recorded our derivatives at fair value according to SFAS No. 157.

In accordance with SFAS No. 157, we use the following fair value hierarchy for determining our derivative fair value measurements:

- Level 1: Valuation is based upon quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and

· Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of the assumptions we believe market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Derivative contracts outstanding at June 30, 2009 and 2008 and December 31, 2008 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; and (g) credit spreads, as well as other relevant economic measures.

In accordance with SFAS No. 157, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. Our assessment of nonperformance risk is generally derived from the credit default swap market or from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at June 30, 2009 and 2008 and December 31, 2008.

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The following table provides the fair value measurements for our derivative assets and liabilities as of June 30, 2009 and 2008 and December 31, 2008 in accordance with the fair value hierarchy under SFAS No. 157:

Thousands	Description of Derivative Inputs	June 30, 2009	June 30, 2008	Dec. 31, 2008
Level 1	Quoted prices in active markets	$ -	$ -	$ -
Level 2	Significant other observable inputs	(73,314)	58,561	(153,643)
Level 3	Significant unobservable inputs	-	-	-
		$ (73,314)	$ 58,561	$ (153,643)

10. Derivative Instruments

We enter into forward contracts and other related financial transactions that qualify as derivative instruments under SFAS No. 133, "Accounting for Derivatives," as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133). We utilize derivative financial instruments primarily to manage commodity prices related to natural gas supply requirements and interest rates related to existing or anticipated debt issuances.

As in the prior two gas years, our strategy entering the 2008-09 gas year (November 1, 2008 – October 31, 2009) was to hedge up to a targeted level of approximately 75 percent of our anticipated year-round sales volumes based on normal weather. We do most of our hedging for the upcoming gas year prior to the start of that gas year and include the hedge prices in our annual purchased gas adjustment filing.

The volumes hedged with financial contracts at June 30, 2009 totaled 482 million therms. These amounts include hedged volumes for the current and future gas years. At June 30, 2009, we were 60 to 70 percent hedged for the remainder of the 2008-09 gas year and approximately 40 percent hedged with financial contracts for the 2009-10 gas year based on anticipated sales volumes, with approximately an additional 8 percent hedged with physical supplies in gas storage for the 2009-10 gas year.

In accordance with SFAS No. 161, the following table discloses the balance sheet presentation of our derivative instruments outstanding as of June 30, 2009 and 2008 and December 31, 2008:

Fair Value of Derivative Instruments	June 30, 2009		June 30, 2008		Dec. 31, 2008	
Thousands	Current	Non-Current	Current	Non-Current	Current	Non-Current
Assets: (1)						
Natural gas commodity	$ 5,293	$ 289	$ 54,867	$ 9,218	$ 4,592	$ 146
Total	$ 5,293	$ 289	$ 54,867	$ 9,218	$ 4,592	$ 146
Liabilities: (2)						
Natural gas commodity	$ 69,999	$ 8,844	$ 2,755	$ 1,374	$ 136,290	$ 9,734
Interest rate	-	-	-	1,358	-	11,912
Foreign exchange	53	-	37	-	445	-
Total	$ 70,052	$ 8,844	$ 2,792	$ 2,732	$ 136,735	$ 21,646

(1) Unrealized fair value gains are classified under current- or non-current assets as fair value of non-trading derivatives.
(2) Unrealized fair value losses are classified under current- or non-current liabilities as fair value of non-trading derivatives.

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In accordance with SFAS No. 161, the following table discloses the income statement presentation for the unrealized gains and losses from our derivative instruments outstanding for the three and six months ended June 30, 2009 and 2008. It also illustrates that all of our derivative instruments are related to regulated utility operations and are deferred to balance sheet accounts in accordance with regulatory accounting under SFAS No. 71.

	Three Months Ended				
	June 30, 2009		June 30, 2008		
Thousands	Natural gas commodity (1)	Foreign exchange (3)	Natural gas commodity (1)	Interest rate (2)	Foreign exchange (3)
Cost of sales	$ 44,446	$ -	$ 28,398	$ -	$ -
Other comprehensive income	-	101	(303)	2,255	71
Less:					
Amounts deferred to regulatory accounts on balance sheet	(44,446)	(101)	(28,095)	(2,255)	(71)
Total impact on earnings	$ -	$ -	$ -	$ -	$ -

	Six Months Ended				
	June 30, 2009		June 30, 2008		
Thousands	Natural gas commodity (1)	Foreign exchange (3)	Natural gas commodity (1)	Interest rate (2)	Foreign exchange (3)
Cost of sales	$ (73,261)	$ -	$ 60,823	$ -	$ -
Other comprehensive income	-	(53)	(867)	(1,358)	(37)
Less:					
Amounts deferred to regulatory accounts on balance sheet	73,261	53	(59,956)	1,358	37
Total impact on earnings	$ -	$ -	$ -	$ -	$ -

(1) Unrealized gain (loss) from natural gas commodity hedge contracts is recorded in cost of sales and reclassified to regulatory deferral accounts on the balance sheet in accordance with SFAS No. 71.

(2) Unrealized gain (loss) from interest rate hedge contracts is recorded in other comprehensive income (loss) and reclassified to regulatory deferral accounts on the balance sheet in accordance with SFAS No. 71.

(3) Unrealized gain (loss) from foreign exchange forward purchase contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet in accordance with SFAS No. 71.

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In accordance with SFAS No. 161, the gross derivative liability excludes the netting of collateral. We had no collateral posted during the six months ended June 30, 2009. We attempt to minimize our potential exposure to collateral calls by our counterparties to manage our liquidity risk. Based on our current credit rating, most counterparties allow us credit limits that range from $15 million to $25 million before we become obligated to post collateral. We measure our collateral call exposure as contractually required under collateral support agreements. We also measure our collateral call exposure with calls for adequate assurance, which is not specific as to amount of credit limit allowed, but could potentially arise if we were to be exposed to a material adverse change. Based upon the current unrealized loss of $72.9 million, the fair value associated with estimated collateral calls is included in the table below. The following table discloses the estimates with and without expected adequate assurance calls, using outstanding derivative instruments at June 30, 2009, based on current gas prices and with various credit rating scenarios for NW Natural.

Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$ -	$ 889	$ 13,679	$ 53,304
Without Adequate Assurance Calls	$ -	$ -	$ -	$ 10,290	$ 44,915

In the three and six months ended June 30, 2009, we realized net losses of $42.4 million and $121.7 million, respectively, from the settlement of natural gas hedge contracts, which were recorded as increases to the cost of gas, compared to net gains of $17.0 million and $21.3 million, respectively, for the three and six months ended June 30, 2008, which were recorded as decreases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts. We settled our $50 million interest rate swap in March 2009 concurrent with our issuance of the underlying long-term debt and realized a $10.1 million effective hedge loss, which will be amortized to interest expense over the term of the debt.

We are exposed to derivative credit risk primarily through securing pay-fixed natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases we require guarantees or letters of credit in order for a counterparty to meet our credit requirements.

Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty’s credit rating. We do not speculate on derivatives. We utilize derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions and market news. We utilize a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. We use the results of the model to establish at-risk trading limits. The duration of our credit risk for all outstanding derivatives currently does not extend beyond October 31, 2012.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss, but we would expect such loss to be eligible for regulatory deferral and rate recovery, subject to prudency review. All of our existing counterparties currently have investment-grade credit ratings.

As of June 30, 2009, all outstanding natural gas hedge contracts were scheduled to mature on or before October 31, 2012.

11. Commitments and Contingencies

Environmental Matters

We own, or have previously owned, properties that are likely to require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study and evaluate the extent of our potential environmental liabilities at each identified site. Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the amount or range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot currently be reasonably estimated. See Part II, Item 8., Note 12, in the 2008 Form 10-K.

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The status of each site currently under investigation is provided below.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality's (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised Upland Remediation Investigation Report and submitted it to the ODEQ for review. In November 2007, we submitted a Focused Feasibility Study for groundwater source control which ODEQ conditionally approved in March 2008. Source control design is underway. We have a net liability balance of $19.0 million at June 30, 2009 for the Gasco site, which is estimated at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). In 2005, ODEQ directed NW Natural to complete a Remedial Investigation/Feasibility Study (RI/FS) for manufactured gas plant wastes on the uplands at this site. ODEQ approved NW Natural's investigation work plan, and field work for the investigation is ongoing. The net liability balance at June 30, 2009 for the Siltronic site is $0.9 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes the area adjacent to the Gasco and Siltronic sites. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor RI/FS. The submittal of the Remedial Investigation Report to the EPA is expected in 2009, with the submittal of the Feasibility Study to the EPA anticipated in 2010. The EPA and the Lower Willamette Group are conducting focused studies on approximately eleven miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. We continue to receive estimates of additional expenditures related to our RI/FS development and environmental remediation. In August 2008, we signed a cooperative agreement to participate in a phased natural resource damage assessment, with the intent to identify what, if any, additional information is necessary to estimate further liabilities sufficient to support an early restoration-based settlement of natural resource damage claims.

In November 2007, the EPA invited all parties to whom it had then sent notices of potential liability for the Portland Harbor site to a meeting to discuss EPA Region 10's expectation of a comprehensive settlement offer regarding implementation of the Portland Harbor record of decision, shortly after it issues such decision. Additional potentially responsible parties were subsequently invited to participate in discussions concerning a settlement process. To date, 72 of these parties have executed an initial agreement to participate in a non-judicial allocation process intended to resolve the parties' liabilities, if any, to the EPA and to one another. As of June 30, 2009, we have accrued a net balance of $12.8 million for this site, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

In April 2004 we entered into an Administrative Order on Consent providing for early action removal of a specific deposit of tar in the river sediments adjacent to the Gasco site. We completed this removal of the tar deposit in the Portland Harbor in October 2005, and on November 5, 2005 the EPA approved the completed project. The total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $10.8 million. To date, we have paid $10.2 million on work related to the removal of the tar deposit. As of June 30, 2009, we have a remaining net liability balance of $0.6 million for our estimate of ongoing costs related to this tar deposit removal.

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Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (the Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2007, we received notice that this site was added to the ODEQ's list of sites where releases of hazardous substances have been confirmed and to its list where additional investigation or cleanup is necessary. We are currently performing an environmental investigation of the property with the ODEQ's Independent Cleanup Pathway. As of June 30, 2009, we have a net liability balance of $0.5 million accrued for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. Although it is near but outside the geographic scope of the current Portland Harbor site sediment studies, the EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that it could be managed separately from the Portland Harbor site under ODEQ authority. Work plans for sediment investigation and a historical report have been submitted to ODEQ. ODEQ approval of the sediment investigation work plan is pending. As of June 30, 2009, we have an estimated net liability balance of $0.2 million for the study of the site, which will include investigation of sediments and providing the report of historical upland activities. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Oregon Steel Mills site. See "Legal Proceedings," below.

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at June 30, 2009 and 2008 and December 31, 2008:

	Current Liabilities			Non-Current Liabilities		
Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008	June 30, 2009	June 30, 2008	Dec. 31, 2008
Gasco site	$ 11,373	$ 8,122	$ 6,012	$ 7,615	$ 12,406	$ 14,071
Siltronic site	722	1,211	682	179	-	332
Portland Harbor site	-	1,348	277	13,401	12,864	13,642
Central Service Center site	-	-	-	523	529	526
Front Street site	221	-	-	-	-	294
Other sites	-	-	-	90	83	80
Total	$ 12,316	$ 10,681	$ 6,971	$ 21,808	$ 25,882	$ 28,945

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the Oregon Public Utility Commission (OPUC) approved our request to defer and seek recovery of unreimbursed environmental costs associated with certain named sites, including those described above. Also, beginning in 2006 the OPUC authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, these authorizations have been extended through January 25, 2010.

On a cumulative basis, we have recognized a total of $72.6 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $38.5 million has been spent to date and $34.1 million is reported as an outstanding liability. At June 30, 2009, we had a regulatory asset of $70.1 million, which includes $33.7 million of total paid expenditures to date, $28.7 million for additional environmental costs expected to be paid in the future and accrued interest of $7.7 million. We believe the recovery of these deferred charges is probable through the regulatory process. We intend to pursue recovery of an insurance receivable and environmental regulatory deferrals from insurance carriers under our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of most of our environmental costs to date probable based on a combination of factors including: a review of the terms of our insurance policies; the financial condition of the insurance companies providing coverage; a review of successful claims filed by other utilities with similar gas manufacturing facilities; and Oregon law that allows an insured party to seek recovery of “all sums” from one insurance company. We have initiated settlement discussions with a majority of our insurers but continue to anticipate that our overall insurance recovery effort will extend over several years.

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We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we do not expect to have completed our insurance recovery efforts during that time period. As such we have classified our regulatory assets for environmental cost deferrals as non-current. The following table summarizes the non-current regulatory assets relating to environmental sites at June 30, 2009 and 2008 and December 31, 2008:

	Non-Current Regulatory Assets		
Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008
Gasco site	$ 32,688	$ 29,898	$ 30,707
Siltronic site	2,367	2,247	2,327
Portland Harbor site	33,727	31,092	31,791
Central Service Center site	548	545	545
Front Street site	350	11	338
Other sites	371	366	396
Total	$ 70,051	$ 64,159	$ 66,104

Legal Proceedings

We are subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows.

Oregon Steel Mills site. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial and discovery is ongoing. We do not expect that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

12. Subsequent Event

On July 20, 2009, the governor of Oregon signed House Bill 3405 establishing increases in the state income tax for corporations. The corporate income tax rate in Oregon for 2009 and 2010 will increase from 6.6 percent to 7.9 percent for corporations with taxable income over $250,000. For tax years 2011 and 2012, the income tax rate will decrease to 7.6 percent, and for years after 2012 the tax rate will return to the current 6.6 percent, except for corporations with taxable income over $10 million the tax rate will remain at 7.6 percent. The new tax rates are retroactive to January 1, 2009. We are in the process of re-measuring our deferred income tax assets and liabilities in accordance with SFAS No. 109, “Accounting for Income Taxes,” and determining the accounting recognition for utility regulation in accordance with SFAS No. 71. We will seek appropriate rate increases to restore our deferred income tax assets and liabilities to the necessary level needed to recover the higher Oregon excise tax rate. With respect to our non-regulated business segments, we anticipate that we will need to record an immaterial charge to income tax expense for the impact on those earnings from the higher Oregon excise tax rate.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of Northwest Natural Gas Company's (NW Natural) financial condition, including the principal factors that affect results of operations. This discussion refers to our consolidated activities for the three and six months ended June 30, 2009 and 2008. Unless otherwise indicated, references in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in this report. This discussion should be read in conjunction with our 2008 Annual Report on Form 10-K (2008 Form 10-K).

The consolidated financial statements include the accounts of NW Natural and its wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and an equity investment in a proposed natural gas pipeline (Palomar). These accounts consist of our regulated local gas distribution business, our regulated gas storage businesses, and other regulated and non-regulated investments primarily in energy-related businesses. In this report, the term "Utility" is used to describe our regulated local gas distribution segment, and the term "Non-utility" is used to describe our gas storage segment (gas storage) and our other regulated and non-regulated investments and business activities (other segment) (see "Strategic Opportunities," below, and Note 2).

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on earnings. All references in this section to earnings per share are on the basis of diluted shares (see Part II, Item 8., Note 1, "Earnings Per Share," in our 2008 Form 10-K). We also believe that showing operating revenues and margins excluding the June 2009 refund of gas cost savings to customers facilitates more meaningful comparisons of operating revenues and margins between 2008 and 2009. We use such non-GAAP (i.e. not generally accepted accounting principles) financial measures in analyzing our results of operations and believe that they provide useful information to investors and creditors in evaluating our financial condition.

Executive Summary

Results for the second quarter of 2009 include:

- Consolidated net income decreased 6 percent to $3.1 million in the second quarter of 2009, compared to $3.3 million in the second quarter of 2008;
- Net operating revenues (margin) increased 5 percent from $62.6 million to $65.9 million in 2009, but the margin gain was partially offset by a 3 percent increase in total operating expenses;
- Income from utility operations increased 20 percent from $7.5 million in 2008 to $9.0 million in 2009, while income from gas storage operations decreased 1 percent or less than $0.1 million;
- Cash flow from operations increased 45 percent from $138.1 million in 2008 to $199.8 million in 2009;
- Gas cost savings of $35.3 million were refunded to Oregon and Washington customers due to lower gas prices;
- Twelve-month customer growth rate declined to 0.8 percent; and
- A new five-year contract was executed with our bargaining unit employees, effective July 13, 2009.

Issues, Challenges and Performance Measures

Managing the utility business in a period of gas price volatility. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility's residential, commercial and industrial customers on firm service. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon our utility's gas load forecast for core utility customers. We hedged gas prices for the majority of our gas purchases for the current gas contract year that began on November 1, 2008, and we believe we have sufficient contracted supplies of natural gas to meet the needs of our core utility customers. During the six months ended June 30, 2009, the market price of natural gas continued to be below the prices embedded in our customers' rates through our annual purchased gas adjustment (PGA) tariff, which resulted in gas cost savings for customers and shareholders from purchases of gas where prices were not hedged. Gas costs lower than those set in the PGA may positively impact earnings due to an incentive sharing mechanism in Oregon. Conversely, gas costs higher than those set in the PGA may negatively impact earnings and may also affect our competitive advantage because they could reduce our ability to add residential and commercial customers and potentially cause industrial customers to shift their energy needs to alternative fuel sources. Our PGA cost sharing mechanism, along with gas hedging strategies and inventories in storage, enables us to manage and reduce earnings risk exposure due to higher gas costs. We have been hedging gas prices for the next gas contract year, and to a certain extent for the next three years, based on current market prices for those future periods. We are also continuing to evaluate and develop other gas acquisition strategies to manage gas prices for customers beyond three years and efficiently meet demands. Based on today's hedge levels and current forward prices for natural gas, we expect to have a customer rate decrease of 15 to 20 percent effective November 1, 2009.

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Economic weakness and financial market stress. Continued weakness in local and U.S. economies have resulted in significant negative pressure on consumer demand and business spending. These conditions have had a negative impact on our financial results including customer growth, margins, bad debt expense, and could have a negative impact on net pension and interest costs. For example, our 12-month customer growth rate slowed to 0.8 percent at June 30, 2009 compared to 2.5 percent at June 30, 2008. Based on current market conditions, we expect lower customer growth rates to continue and possibly decline more if economic conditions deteriorate further. However, due to a relatively low market penetration of natural gas in our service territory compared to the rest of the country, along with the forecast for long-term population growth in the Pacific Northwest, the potential for environmental initiatives in Oregon and Washington that could favor natural gas as an energy source, and our ongoing efforts to convert existing homes from other heating fuels to natural gas, we still have the potential to continue adding customers despite tough market conditions.

Our funding for strategic opportunities and other capital investments is dependent upon our ability to access capital markets and maintain working capital sufficient to meet operating requirements. In March 2009, and again in July 2009, we were able to issue long-term debt totaling $125 million at favorable rates (see Note 5). We continue to focus on: maintaining a strong balance sheet; providing sufficient liquidity; accessing capital markets as needed; managing critical business risks; and maintaining a balanced capital structure through the appropriate issuance of equity or long-term debt securities. If we are unable to secure financing to fund certain strategic opportunities, we may look at potentially re-prioritizing the use of existing resources or consider delaying investments until market conditions improve.

We believe that, despite the current economic and credit market environment, our financial condition and liquidity position remain strong and afford us access to capital at reasonable costs. See Part I, Item 1A., “Risk Factors,” and Part II, Item 7., “Financial Condition—Liquidity and Capital Resources,” in our 2008 Form 10-K.

Performance Measures. In order to deal with these and other challenges affecting our business, we continue to refine our strategic plan to map our course over the next several years. The plan includes strategies: for further improving our core gas distribution business; for growing our non-utility gas storage business; for investing in new natural gas infrastructure in the region; and for maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support new clean technologies. The key performance measures we intend to use in monitoring progress against our goals in these areas include, but are not limited to: earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction ratings; capital, operations and maintenance expense per customer; and non-utility earnings before interest, taxes, depreciation and amortization, commonly referred to as EBITDA.

Strategic Opportunities

Business Process Improvements. To address the current economic and competitive challenges, we continue to evaluate and implement business strategies to improve efficiencies. Our goal is to integrate, consolidate and streamline operations and support our employees with new technology tools. In 2008, we implemented the first phase of our new enterprise resource planning (ERP) system, and in February 2009 we implemented the second phase with our fixed assets, payroll and construction work management systems. This substantially completes our transition to the new ERP system, which is designed to reduce the number of technology platforms and improve overall operating efficiencies by:

- integrating systems and data;
- automating control procedures with auditable financial and operational workflows; and
- improving monthly closing and financial reporting processes.

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We initiated a project to automate the reading of gas meters (AMR) for the remaining two-thirds of our customers in 2008. Meters equipped with this new technology electronically transmit usage data to receiving devices located in our vehicles as they are driven in the area, substantially reducing the labor costs associated with manually reading meters. The capital cost of this project is estimated to be $30 million, and in January 2009 we filed for and subsequently received approval for regulatory deferral of this investment in Oregon (see "Results of Operations—Regulatory Matters—Rate Mechanisms—AMR Deferral Application," below). Also in 2008, we initiated an automated dispatching system, which provides integrated planning and scheduling with global positioning system capabilities to more effectively collect and distribute data.

In 2009, we began to identify additional areas for further cost reductions based on work load declines primarily related to slower customer growth. We intend to mitigate the potential impact of the decline by aligning current staffing levels with work load demands and reducing operating costs. At this time, it is likely we will make reductions that equate to between 50 and 100 full-time positions, with a majority of those reductions made by the end of this fiscal year. See "Issues, Challenges and Performance Measures—Economic Weakness and Financial Market Stress," above.

These technology investments, workforce reductions and other initiatives are expected to facilitate process improvements, contribute to long-term operational efficiencies and reduce operating expenses throughout NW Natural.

Gas Storage Development. In September 2007, we initiated a joint project with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. We formed a wholly-owned subsidiary, Gill Ranch, to plan, develop and operate the facility. In July 2008, Gill Ranch filed an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity. In December 2008, the CPUC indicated that our application qualified for a Mitigated Negative Declaration, which allows an expedited review process. A decision on the application is expected to be received by the end of this year. Gill Ranch's provision of market-based rate storage services in California will be subject to CPUC regulation including, but not limited to, service terms and conditions, tariff compliance, securities issuances, lien grants and sales of property. Our share of the total project is estimated to be between $160 and $180 million. Our share represents 75 percent of the total cost of the initial development, which includes an estimated total 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline. The initial development of gas storage at Gill Ranch is currently scheduled to be in-service by late 2010.

Pipeline Diversification. Currently, we depend on a single bi-directional interstate pipeline to ship gas supplies to our distribution system. Palomar Gas Transmission, LLC (Palomar), a wholly-owned subsidiary of Palomar Gas Holdings, LLC, (PGH), is seeking to build a new transmission pipeline that would provide a new transmission pipeline interconnection with our gas distribution system. PGH is owned 50 percent by NW Natural and 50 percent by Gas Transmission Corporation (GTN), an indirect wholly-owned subsidiary of TransCanada Corporation. The proposed Palomar pipeline is a 217-mile natural gas transmission pipeline in Oregon designed to serve our utility and the growing markets in Oregon and other parts of the western United States. The project includes an east and west segment. The east segment of the Palomar pipeline would extend approximately 111 miles west from an interconnection with GTN's existing interstate transmission mainline near Maupin, Oregon to an interconnection with NW Natural's gas distribution system near Molalla, Oregon. The west segment would then extend approximately 106 miles further west to other potential additional interconnections including a possible connection to one of the several liquefied natural gas (LNG) terminals proposed to be built on the Columbia River. The east segment of Palomar would diversify NW Natural's gas delivery options and enhance the reliability of service to our utility customers by providing an alternate transportation path for gas purchases from western Canada and the U.S. Rocky Mountains. The west segment of Palomar would provide our utility customers with potential access to a new source of gas supply if an LNG terminal is built on the Columbia River. The Palomar pipeline would be regulated by the

Federal Energy Regulatory Commission (FERC). In December 2008, Palomar filed for a Certificate of Public Convenience and Necessity with the FERC. See "Financial Condition—Cash Flows—Investing Activities," below for further discussion on Palomar.

Earnings and Dividends

Three months ended June 30, 2009 compared to June 30, 2008:

Net income was $3.1 million, or $0.12 per share, for the three months ended June 30, 2009, compared to $3.3 million, or $0.12 per share, for the same period last year.

The primary factors contributing to the $0.2 million decrease in net income were:

· a $5.8 million net decrease in utility margin from sales and transportation customers, after weather and decoupling mechanism adjustments, primarily due to a rate decrease for lower depreciation rates and lower sales due to warmer weather and weak economic conditions (see Results of Operations – Business Segments—Utility Operations," below);
· a $4.3 million increase in operations and maintenance expense primarily due to higher pension expense, bonus accruals, and health care benefit expenses; and
· a $1.2 million decrease in other income reflecting a last year's gain from the sale of our investment in a leased aircraft in 2008.

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Partially offsetting the above factors were:

- an $8.1 million increase in utility margin from our regulatory share of gas cost savings, reflecting a margin loss of $5.5 million in 2008 compared to a margin gain of $2.6 million in 2009; and
- a $2.6 million decrease in depreciation expense reflecting lower depreciation rates effective January 1, 2009, which was offset by a corresponding decrease in utility margin referred to above.

Six months ended June 30, 2009 compared to June 30, 2008:

Net income was $50.4 million, or $1.90 per share, for the six months ended June 30, 2009, compared to $46.5 million, or $1.75 per share, for the same period last year.

The primary factors contributing to the $4.0 million increase in net income were:

- a $16.9 million increase in utility margin from our regulatory share of gas cost savings, reflecting a margin loss of $5.8 million in 2008 compared to a margin gain of $11.1 million in 2009;
- a $2.5 million increase from a regulatory adjustment for income taxes paid versus collected in rates; and
- a $4.8 million decrease in depreciation expense primarily from lower depreciation rates effective January 1, 2009.

Partially offsetting the above factors were:

- a $9.8 million increase in operations and maintenance expense primarily due to higher pension expense, bonus accruals, and health care benefit expenses; and
- a $6.6 million net decrease in utility margin from sales and transportation customers, after weather and decoupling mechanism adjustments, primarily due to a rate decrease for lower depreciation rates referred to above.

Dividends paid on our common stock were 39.5 cents per share in the second quarter of 2009, compared to 37.5 cents per share in the second quarter of 2008. In July 2009, the Board of Directors declared a quarterly dividend on our common stock of 39.5 cents per share, payable on August 14, 2009 to shareholders of record on July 31, 2009. The current indicated annual dividend rate is $1.58 per share.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America, management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions. Our most critical estimates and judgments include accounting for:

- regulatory cost recovery and amortizations;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions;
- income taxes; and
- environmental contingencies.

There have been no material changes to the information provided in the 2008 Form 10-K with respect to the application of critical accounting policies and estimates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates," in the 2008 Form 10-K). Management has discussed the estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board.

Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 1.

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Results of Operations

Regulatory Matters

Regulation and Rates

We are currently subject to regulation with respect to, among other matters, rates and systems of accounts set by the Oregon Public Utility Commission (OPUC), the Washington Utilities and Transportation Commission (WUTC) and the FERC. The OPUC and WUTC also regulate our issuance of securities. Approximately 90 percent of our utility gas volumes are delivered to, and utility operating revenues were derived from, Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the Oregon and southwest Washington economies in general, and by the pace of growth in the residential and commercial markets in particular, by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant. See Part II, Item 7., "Results of Operations—Regulatory Matters," in the 2008 Form 10-K.

At June 30, 2009 and 2008 and at December 31, 2008, the amounts deferred as regulatory assets and liabilities were as follows:

		Current	
Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008
Regulatory assets:			
Unrealized loss on non-trading derivatives(1)	$ 70,052	$ 1,912	$ 136,735
Pension and other postretirement benefit obligations(2)	8,074	2,792	8,074
Other(4)	11,053	1,044	2,510
Total regulatory assets	$ 89,179	$ 5,748	$ 147,319
Regulatory liabilities:			
Gas costs payable	$ 19,010	$ 24,307	$ 5,284
Unrealized gain on non-trading derivatives(1)	5,293	53,999	4,592
Other(4)	6,486	6,064	10,580
Total regulatory liabilities	$ 30,789	$ 84,370	$ 20,456

		Non-Current	
Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008
Regulatory assets:			
Unrealized loss on non-trading derivatives(1)	$ 8,844	$ 2,732	$ 21,646
Income tax asset	70,096	69,547	69,948
Pension and other postretirement benefit obligations(2)	109,833	26,203	113,869
Environmental costs - paid(3)	41,362	32,087	36,135
Environmental costs - accrued but not yet paid(3)	28,689	32,072	29,969
Other(4)	11,220	10,680	16,903
Total regulatory assets	$ 270,044	$ 173,321	$ 288,470
Regulatory liabilities:			
Gas costs payable	$ 3,758	$ 1,263	$ 1,868
Unrealized gain on non-trading derivatives(1)	289	9,218	146
Accrued asset removal costs	231,880	214,044	223,716
Other(4)	2,337	2,551	2,427

Total regulatory liabilities	$	238,264	$	227,076	$	228,157

(1) An unrealized gain or loss on non-trading derivatives does not earn a rate of return or a carrying charge. These amounts, when realized at settlement, are recoverable through utility rates as part of the PGA mechanism.

(2) Qualified pension plan and other postretirement benefit obligations are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in net periodic benefit cost (see Note 7).

(3) Environmental costs are related to those sites that are approved for regulatory deferral. We earn the authorized rate of return as a carrying charge on amounts paid, whereas the amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended.

(4) Other primarily consists of deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

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Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including gas storage, purchase prices hedged with financial derivatives, interstate pipeline demand charges, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year.

In October 2008, the OPUC and WUTC approved rate changes effective on November 1, 2008 under our PGA mechanisms. The effect of the rate changes was to increase the average monthly bills of Oregon residential customers by 14 percent and those of Washington residential customers by 21 percent.

Under the new Oregon PGA incentive sharing mechanism, effective November 1, 2008, we are required to select, by August 1 of each year, either an 80 percent deferral or 90 percent deferral of higher or lower gas costs compared to PGA prices such that the impact on current earnings from the gas cost sharing is either 20 percent or 10 percent, respectively. We are also subject to an annual earnings review to see if the utility is earning over an allowed threshold. If utility earnings exceed a threshold level, then 33 percent of the excess amount above the threshold will be deferred for future refund to customers. Under our current mechanism, if we select the 80 percent deferral, we retain all of our earnings up to 150 basis points above the currently authorized return on equity (ROE), or if we select the 90 percent deferral, we retain all of our earnings up to 100 basis points above the currently authorized ROE. For the current PGA year, we selected the 80 percent deferral. In August 2009, however, we selected the 90 percent deferral for the PGA year beginning November 1, 2009. The earnings threshold is subject to adjustment up or down each year depending on movements in long-term interest rates.

In 2008, the earnings threshold after adjustment for long-term interest rates was 13.1 percent. In July 2009, we received the final report from the OPUC on our 2008 earnings review, which resulted in a ROE of 9.6 percent. As this is below the earnings threshold, no refund will be made to customers as a result of the 2008 earnings review. There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual purchased gas costs and pass that difference through to customers as an adjustment to future rates.

Regulatory Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer unreimbursed environmental costs associated with certain named sites. The OPUC also authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, these authorizations have been extended through January 25, 2010. See Note 11.

Integrated Resource Plan. The OPUC and WUTC have implemented integrated resource planning (IRP) processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. These plans are consistent with state and energy policy and include:

- an evaluation of supply and demand resources;
- the consideration of uncertainties in the planning process and the need for flexibility to respond to changes; and
- a primary goal of “least cost” service.

In January 2009, the OPUC acknowledged our 2008 IRP. Although the OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. We filed our 2009 IRP with the WUTC in March 2009. In July 2009, the WUTC provided notice that our 2009 IRP met the requirements of the Washington Administrative Code. The WUTC has indicated that the IRP process is one factor it will consider in a prudency review.

System Integrity Program. In July 2004, the OPUC approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, a program mandated by the Pipeline Safety Improvement Act of 2002 and the related rules adopted by the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration. We record these costs as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period ending September 30, and recover the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. In February 2009, the OPUC approved a stipulated agreement to create a new, consolidated system integrity program (SIP). The new SIP will integrate the older and the proposed programs into a single program. The SIP also includes a component for a proposed distribution integrity management program, which will be implemented following the enactment of new federal regulations. Costs will be tracked into rates annually, with recovery to be sought after the first $3.3 million of capital costs. An annual cap for expenditures will be approximately $12 million, but extraordinary costs above the cap may be approved with written consent of all parties.

The SIP allows recovery of costs incurred in Oregon during the period from October 2008 through October 2011, or until the effective date of new rates adopted in the company’s next general rate case. We do not have any special accounting or rate treatment for system integrity program costs incurred in the state of Washington.

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AMR Deferral Application. In 2008, we initiated a project to automate the reading of gas meters for the remaining two-thirds of our customers. The capital cost of this automated meter reading project is estimated to be $30 million, and in January 2009 we filed for approval to defer the costs associated with the AMR project. This request was approved on March 30, 2009. We will continue to defer costs associated with the AMR project, including interest on deferred balances, until we amortize those balances. We are currently negotiating an agreement regarding the recovery of the AMR investment, with a target of beginning recovery in the 2010 PGA filing.

Depreciation Study. In December 2008, the OPUC and WUTC approved our filed depreciation study and our request to change the amortization of our regulatory asset account balance on pre-1981 plant. These approvals specifically authorized the implementation of new depreciation rates in Oregon and Washington, with a corresponding decrease to customer rates effective January 1, 2009. The new amortization schedule on pre-1981 regulatory assets, with a corresponding increase to customer rates, became effective January 1, 2009 in Washington and will be effective November 1, 2009 in Oregon. The implementation of the new rates decreases depreciation expense and increases income tax expense, both of which are offset by a corresponding change in utility operating revenues. In addition, in December 2008 we filed our depreciation study with the FERC requesting approval to apply these same new depreciation rates to our gas storage business assets. Our FERC filing was approved in May 2009 and the new depreciation rates were made effective as of January 1, 2009.

Customer Refunds for Gas Cost Incentive Sharing. For the period between November 1, 2008 and March 31, 2009, our actual gas costs were significantly lower than the gas costs embedded in customer rates. As a result, our PGA incentive sharing mechanism recorded 80 percent of these gas cost savings attributed to Oregon, and 100 percent of the savings attributed to Washington, to a regulatory account for refund to customers (see “Purchased Gas Adjustment,” above). Ordinarily, these refunds would be included in customer rates in the next year’s PGA filing, but this year we received special regulatory approval to refund the accumulated gas costs to our Oregon and Washington customers. In June 2009, we refunded $31.0 million to our Oregon customers and $4.3 million to our Washington customers through billing credits.

Rate Adjustment for Income Taxes Paid and Interstate Storage Credits. In June 2009, $6.2 million was collected from customers, representing the 2007 surcharge for an adjustment for income taxes paid. The surcharge was included in operating revenues from residential, commercial and industrial customers (see “Business Segments – Utility Operations—Regulatory Adjustment for Income Taxes Paid,” below), but it was more than offset by a refund to customers of $7.2 million from a sharing mechanism for interstate storage.

Business Segments - Utility Operations

Our utility margin results are primarily affected by customer growth and to a certain extent by changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation rate mechanism that adjusts revenues to offset changes in margin resulting from increases or decreases in residential and commercial customer consumption. We also have a weather normalization mechanism that adjusts revenues and customer bills up or down to offset changes in margin resulting from above- or below-average temperatures during the winter heating season (see Part II, Item 7., “Results of Operations—Regulatory Matters—Rate Mechanisms,” in the 2008 Form 10-K). Both mechanisms are designed to reduce the volatility of our utility earnings.

Three months ended June 30, 2009 compared to June 30, 2008:

Utility operations resulted in net income of $0.4 million, or 2 cents per share, in the second quarter of 2009 compared to a net loss of $0.7 million, or 3 cents per share, in the second quarter of 2008. Net income from utility operations is typically a small net gain or loss during the second quarter each year because of the reduced use of natural gas in the spring and early summer. The $1.1 million increase over 2008 is primarily due to lower gas costs in 2009 (see "Cost of Gas Sold," below), partially offset by warmer weather and reduced customer use in 2009. Total utility volumes sold and delivered in the second quarter of this year decreased by 20 percent over last year, while total utility margin increased by 5 percent, primarily due to an $8.1 million swing in gas cost savings from our incentive sharing mechanism.

Six months ended June 30, 2009 compared to June 30, 2008:

In the six months ended June 30, 2009, utility operations contributed net income of $45.7 million or $1.72 per share, compared to $39.8 million or $1.50 per share in 2008. Total utility volumes sold and delivered in the six months ended June 30, 2009 decreased by 13 percent over last year, while total utility margin increased by 7 percent, primarily due to a $16.9 million swing in gas cost savings from our incentive sharing mechanism.

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The following tables summarize the composition of utility volumes, operating revenues and margin:

Thousands, except degree day and customer data	Three months ended June 30, 2009	2008	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	58,156	78,444	(20,288)
Commercial sales	43,497	52,161	(8,664)
Industrial - firm sales	8,568	10,556	(1,988)
Industrial - firm transportation	29,377	41,868	(12,491)
Industrial - interruptible sales	17,368	21,799	(4,431)
Industrial - interruptible transportation	52,229	57,784	(5,555)
Total utility volumes sold and delivered	209,195	262,612	(53,417)
Utility operating revenues - dollars:			
Residential sales	$ 72,491	$ 95,660	$ (23,169)
Commercial sales	42,311	53,385	(11,074)
Industrial - firm sales	7,949	9,531	(1,582)
Industrial - firm transportation	1,442	1,643	(201)
Industrial - interruptible sales	13,280	16,011	(2,731)
Industrial - interruptible transportation	2,039	1,936	103
Regulatory adjustment for income taxes paid (1)	(626)	(673)	47
Other revenues	4,290	8,366	(4,076)
Total utility operating revenues	143,176	185,859	(42,683)
Cost of gas sold	79,359	124,004	44,645
Revenue taxes	3,753	4,672	919
Utility margin	$ 60,064	$ 57,183	$ 2,881
Utility margin: (2)			
Residential sales	$ 34,901	$ 44,328	$ (9,427)
Commercial sales	14,793	18,713	(3,920)
Industrial - sales and transportation	6,524	7,054	(530)
Miscellaneous revenues	1,474	1,480	(6)
Gain (loss) from gas cost incentive sharing	2,647	(5,471)	8,118
Other margin adjustments	496	13	483
Margin before regulatory adjustments	60,835	66,117	(5,282)
Weather normalization adjustment	(756)	(6,184)	5,428
Decoupling adjustment	611	(2,077)	2,688
Regulatory adjustment for income taxes paid (1)	(626)	(673)	47
Utility margin	$ 60,064	$ 57,183	$ 2,881
Customers - end of period:			
Residential customers	599,614	594,121	5,493
Commercial customers	61,938	61,861	77
Industrial customers	923	936	(13)
Total number of customers - end of period	662,475	656,918	5,557
Actual degree days	577	860	
Percent colder (warmer) than average weather (3)	(16%)	26%	

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Thousands, except degree day and customer data	Six months ended June 30, 2009	2008	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	236,545	260,812	(24,267)
Commercial sales	146,614	159,117	(12,503)
Industrial - firm sales	20,605	25,098	(4,493)
Industrial - firm transportation	64,778	90,854	(26,076)
Industrial - interruptible sales	40,267	47,841	(7,574)
Industrial - interruptible transportation	111,696	128,166	(16,470)
Total utility volumes sold and delivered	620,505	711,888	(91,383)
Utility operating revenues - dollars:			
Residential sales	$ 325,548	$ 321,343	$ 4,205
Commercial sales	171,661	168,349	3,312
Industrial - firm sales	21,653	23,353	(1,700)
Industrial - firm transportation	2,844	3,229	(385)
Industrial - interruptible sales	35,219	35,692	(473)
Industrial - interruptible transportation	3,961	4,031	(70)
Regulatory adjustment for income taxes paid (1)	2,887	382	2,505
Other revenues	12,203	12,122	81
Total utility operating revenues	575,976	568,501	7,475
Cost of gas sold	363,523	369,916	6,393
Revenue taxes	14,295	14,023	(272)
Utility margin	$ 198,158	$ 184,562	$ 13,596
Utility margin: (2)			
Residential sales	$ 121,234	$ 131,920	$ (10,686)
Commercial sales	48,567	53,347	(4,780)
Industrial - sales and transportation	13,946	15,385	(1,439)
Miscellaneous revenues	3,366	3,208	158
Gain (loss) from gas cost incentive sharing	11,079	(5,794)	16,873
Other margin adjustments	994	329	665
Margin before regulatory adjustments	199,186	198,395	791
Weather normalization adjustment	(9,470)	(13,732)	4,262
Decoupling adjustment	5,555	(483)	6,038
Regulatory adjustment for income taxes paid (1)	2,887	382	2,505
Utility margin	$ 198,158	$ 184,562	$ 13,596
Actual degree days	2,598	2,840	
Percent colder (warmer) than average weather (3)	2%	11%	

(1)Regulatory adjustment for income taxes is described below under “Regulatory Adjustment for Income Taxes Paid.”
(2)Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.
(3)Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

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In June 2009 we refunded $35.3 million to our Oregon and Washington customers. The following non-GAAP table summarizes the impact of the refund on our operating revenues and margins for the three and six months ended June 30, 2009, and a comparison to 2008.

	Three months ended June 30, 2009			
Thousands	As Reported	Refund	Excluding Refund (Non-GAAP)	June 30, 2008
Utility operating revenues:				
Residential sales	$ 72,491	$ (19,679)	$ 92,170	$ 95,660
Commercial sales	42,311	(11,423)	53,734	53,385
Industrial - firm sales	7,949	(1,515)	9,464	9,531
Industrial - firm transportation	1,442	-	1,442	1,643
Industrial - interruptible sales	13,280	(2,673)	15,953	16,011
Industrial - interruptible transportation	2,039	-	2,039	1,936
Regulatory adjustment for income taxes paid	(626)	-	(626)	(673)
Other revenue	4,290	-	4,290	8,366
Total utility operating revenues	143,176	(35,290)	178,466	185,859
Cost of gas sold	79,359	34,206	113,565	124,004
Revenue taxes	3,753	887	4,640	4,672
Utility margin	$ 60,064	$ (197)	$ 60,261	$ 57,183

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	Six months ended June 30, 2009			
Thousands	As Reported	Refund	Excluding Refund (Non-GAAP)	June 30, 2008
Utility operating revenues:				
Residential sales	$ 325,548	$ (19,679)	$ 345,227	$ 321,343
Commercial sales	171,661	(11,423)	183,084	168,349
Industrial - firm sales	21,653	(1,515)	23,168	23,353
Industrial - firm transportation	2,844	-	2,844	3,229
Industrial - interruptible sales	35,219	(2,673)	37,892	35,692
Industrial - interruptible transportation	3,961	-	3,961	4,031
Regulatory adjustment for income taxes paid	2,887	-	2,887	382
Other revenue	12,203	-	12,203	12,122
Total utility operating revenues	575,976	(35,290)	611,266	568,501
Cost of gas sold	363,523	34,206	397,729	369,916
Revenue taxes	14,295	887	15,182	14,023
Utility margin	$ 198,158	$ (197)	$ 198,355	$ 184,562

The refunds represent the customers' portion of gas cost savings realized between November 1, 2008 and March 31, 2009, which had been deferred, with interest, pursuant to our PGA tariffs in Oregon and Washington (see "Regulatory Matters – Rate Mechanisms," above). The refunds reduced total utility operating revenues for the three and six months ended June 30, 2009 by $35.3 million, cost of gas sold by $34.2 million and revenue taxes by $0.9 million, which resulted in a reduction to margin of $0.2 million. This was offset by other revenue-based expenses like lower uncollectible expense and lower regulatory fees.

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Residential and Commercial Sales

Residential and commercial sales are impacted by customer growth rates, seasonal weather patterns, energy prices, competition from other energy sources and economic conditions. Typically, 80 percent or more of our annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced by our weather normalization mechanism which is effective from December 1 through May 15 of each heating season in Oregon, where about 90 percent of our customers are served. Approximately 10 percent of our eligible Oregon customers opt out of the mechanism each year. In Oregon, we also have a conservation decoupling adjustment mechanism that is intended to break the link between our earnings and the quantity of gas consumed by our customers, so that we do not have an incentive to encourage greater consumption contrary to customers' energy conservation efforts. In Washington, where approximately 10 percent of our customers are served, we do not have a weather normalization or a conservation decoupling mechanism. As a result, we are not completely insulated from earnings volatility due to weather conditions and conservation efforts by customers.

Three months ended June 30, 2009 compared to June 30, 2008:

The primary factors contributing to changes in residential and commercial volumes and operating revenues in the second quarter of this year as compared to the same period last year were:

- sales volumes to residential and commercial customers decreased 22 percent due to warmer weather, customer conservation, and weak economic conditions;
- utility operating revenues decreased $34.2 million or 23 percent, primarily due to $31.1 million of bill credits to customers in June 2009 for the refund of gas cost savings and $2.5 million from rate decreases for lower depreciation expense effective January 1, 2009, which were partially offset by PGA rate increases for higher gas prices effective November 1, 2008; and
- margin decreased $5.2 million or 10 percent, after weather normalization and decoupling mechanism adjustments, primarily due to rate decreases that reflect the lower margin requirements for new depreciation rates and lower volumes due to warmer weather, which was partially offset by the increased margin from customer growth of 0.8 percent over the last 12 months.

Six months ended June 30, 2009 compared to June 30, 2008:

The primary factors contributing to changes in residential and commercial volumes and operating revenues in the six months ended June 30, 2009, compared to the same period last year were:

- sales volumes to residential and commercial customers decreased 9 percent due to warmer weather, customer conservation, and weak economic conditions;
- utility operating revenues increased $7.5 million or 2 percent primarily due to PGA rate increases of 14 to 21 percent in Oregon and Washington, respectively, effective November 1, 2008 and annual customer growth of 0.8 percent, partially offset by $31.1 million in customer refunds for gas cost savings and $6.5 million from rate decreases effective January 1, 2009 for lower depreciation expense; and
- margin decreased $5.2 million or 3 percent, after weather normalization and decoupling adjustments, primarily due to rate decreases that reflect the lower margin requirements for new depreciation rates, which was partially offset by the increased margin from customer growth of 0.8 percent over the last 12 months.

Utility operating revenues include accruals for unbilled revenues (gas delivered but not yet billed to customers) based on estimates of gas deliveries from that month's meter reading dates to month end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenues at the end of each month. At June 30, 2009, accrued unbilled revenue was $18.1 million, compared to $19.7 million at June 30, 2008, with the 8 percent decrease primarily due to the lower volumes partially offset by the higher billing rates mentioned above.

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Industrial Sales and Transportation

Utility operating revenues from the industrial customer sector include commodity costs only for those customers under sales service but not under transportation service. Therefore, industrial customers switching between sales service and transportation service result in swings in operating revenues, but generally our margins are not affected because we do not mark up (i.e. we earn no additional margin) the higher or lower cost of gas. In addition, a significant portion of our margin revenues from our largest industrial customers are in the form of fixed monthly charges. As such, we believe margin is a better measure of performance for the industrial sector.

Three months ended June 30, 2009 compared to June 30, 2008:

The primary factors that impacted results of operations in industrial sales and transportation markets are as follows:

- volumes delivered to industrial customers decreased by 24.5 million therms, or 19 percent;
- utility operating revenues decreased $4.4 million or 15 percent, which included $4.2 million refunded to customers for gas cost savings; and
- margin decreased $0.5 million, or 8 percent, a result of reduced usage due to the current economic environment, which was partially offset by fixed charges not affected by declining use, and by rate decreases related to lower depreciation expense.

Six months ended June 30, 2009 compared to June 30, 2008:

The primary factors that impacted results of operations in industrial sales and transportation markets are as follows:

- volumes delivered to industrial customers decreased by 54.6 million therms, or 19 percent;
- utility operating revenues decreased $2.6 million or 4 percent, which included $4.2 million refunded to customers for gas cost savings; and
- margin decreased $1.4 million, or 9 percent, a result of reduced usage due to the current economic environment, which was partially offset by fixed charges not affected by declining use, and by rate decreases related to lower depreciation expense.

Regulatory Adjustment for Income Taxes Paid

In Oregon, utilities are required to true-up any differences between income taxes authorized to be collected in rates and income taxes actually paid to governmental entities for amounts "properly attributed" to the utilities' regulated operations. Utilities file a tax report with the OPUC reporting these amounts on October 15 of each year. If amounts collected and paid differ by $100,000 or more, then the OPUC orders the utility to establish an automatic rate adjustment to account for the difference, with the rate adjustment to be effective June 1 of each subsequent year.

For the six months ended June 30, 2009, we recognized $2.9 million of incremental margin revenues representing a difference of $2.7 million of federal and state income taxes paid in excess of taxes collected in rates plus accrued interest of $0.2 million attributed to 2007 and 2009 tax years. This indicated surcharge to customers is primarily driven by the gains from gas cost savings under our PGA incentive mechanism. For the six months ended June 30, 2008, we recognized a surcharge of $0.4 million representing $0.3 million attributed to regulated operations for the 2008 tax year and a $0.1 million adjustment for the 2007 tax year.

Other Revenues

Other revenues include miscellaneous fee income as well as utility revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferred gas costs.

Three months ended June 30, 2009 compared to June 30, 2008:

Other revenues were $4.3 million in the second quarter of 2009, a decrease of $4.1 million over the second quarter of 2008, with the decrease due to the June 2009 collection of the regulatory adjustment for income taxes of $6.2 million, a decrease in the interstate storage credits, partially offset by a net increase in the deferral and amortization for the decoupling adjustment. Although the decoupling adjustment and other regulatory deferral collections or surcharges can have a material impact on utility operating revenues, they generally do not have a material impact on margin because they are offset by increases and decreases in customer sales rates.

Six months ended June 30, 2009 compared to June 30, 2008:

Other revenues were $12.2 million in the six months ended June 30, 2009, an increase of $0.1 million over the first half of 2008, with the increase primarily due to a net increase in the deferral and amortization related to the decoupling adjustment, which was partially offset by a decrease in the interstate storage credit compared to 2008 and the collection of the regulatory adjustment for income taxes, mentioned above.

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Cost of Gas Sold

The cost of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use. The OPUC and the WUTC require the natural gas commodity cost to be billed to customers at the same cost incurred or expected to be incurred by the utility. However, under the PGA mechanism in Oregon, our net income is affected by differences between actual and expected purchased gas costs primarily due to changes in market prices and weather, which affects the volume of unhedged purchases. We use natural gas derivatives, primarily fixed-price commodity swaps, in accordance with guidelines set forth in our financial derivatives policies which are designed to help manage our exposure to rising gas prices. Gains and losses from financial hedge contracts are generally reflected in our PGA prices and normally do not impact net income as the hedges are usually 100 percent passed through to customers in annual rate changes, subject to a regulatory prudency review. However, hedge contracts entered into after the annual PGA filing may impact net income to the extent of our share of any gain or loss under the PGA in Oregon. In Washington, 100 percent of the actual gas costs, including all hedge gains and losses, are passed through in customer rates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," and "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," in the 2008 Form 10-K, and Note 10).

Three months ended June 30, 2009 compared to June 30, 2008:

- including the customer refund, total cost of gas sold decreased $44.6 million or 36 percent compared to 2008, while excluding the customer refund, total cost of gas decreased $10.4 million or 8 percent;
- the average gas cost collected through rates, excluding the effect of customer refunds, increased 17 percent from 76 cents per therm in 2008 to 89 cents per therm in 2009, primarily reflecting higher prices that were passed through to customers through PGA rate increases effective November 1, 2008; and
- hedge losses totaling $42.4 million were realized and included in cost of gas this quarter, compared to $17.0 million of hedge gains in the same period of 2008.

The effect on operating results from our gas cost incentive sharing mechanism was a margin gain of $2.6 million in the second quarter of 2009, compared to a margin loss of $5.5 million for the second quarter of 2008.

Six months ended June 30, 2009 compared to June 30, 2008:

- including the customer refund, total cost of gas sold decreased $6.4 million or 2 percent compared to 2008, while excluding the customer refund, total cost of gas increased $27.8 million or 8 percent;
- the average gas cost collected through rates, excluding the effect for customer refunds, increased 20 percent from 75 cents per therm in 2008 to 90 cents per therm in 2009, primarily reflecting higher prices that were passed through to customers through PGA rate increases effective November 1, 2008; and
- hedge losses totaling $121.7 million were realized and included in cost of gas for the six months ended June 30, 2009, compared to $21.3 million of hedge gains in the same period of 2008.

The effect on operating results from our gas cost incentive sharing mechanism was a margin gain of $11.1 million in the six months ended June 30, 2009, compared to a margin loss of $5.8 million in the same period of 2008.

Business Segments Other than Utility Operations

Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility, asset optimization services and Gill Ranch (see Part I, Item 1., "Business Segments—Gas Storage," in our 2008 Form 10-K). For the three months ended June 30, 2009, we earned $2.7 million, or 10 cents per share, compared to $2.5 million, or 9 cents per share, for the same period in 2008. The $0.2 million increase in earnings over 2008 is primarily due to increased revenues from optimization services. For the six months ended June 30, 2009, we earned $4.8 million, or 18 cents per share, compared to $4.9 million, or 18 cents per share, for the same period in 2008.

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In Oregon, we retain 80 percent of pre-tax income from gas storage services and from optimization services when the costs of the capacity being used is not included in utility rates, or 33 percent of pre-tax income from such storage and optimization services when the capacity being used is included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for refund to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage and optimization services.

We are currently developing a second underground storage facility and related pipeline near Fresno, California. This project, Gill Ranch, is expected to serve the California and west coast market (see Note 2). We are also exploring the potential for further development of underground storage reservoirs at Mist in Oregon.

On May 1, 2009, a total of 100,000 therms per day of Mist storage capacity and 50,000 therms per day of compression capacity that had previously been available for interstate storage services was recalled by the utility and committed to use for its core customers. Our last recall was in May 2008. Under a regulatory agreement with the OPUC, non-utility gas storage at Mist, which has been developed in advance of core utility customer needs for interstate storage services, can be recalled by the utility to serve utility customers. Storage capacity recalled by the utility is added to utility rate base at net book value and tracked into utility rates in the next annual PGA filing so there is minimal regulatory lag in cost recovery.

Other

Our other business segment consists of an equity investment in an intrastate pipeline by Financial Corporation, an equity investment in Palomar pipeline, and other non-utility investments and business activities. Financial Corporation's total investment balance was $1.0 million as of June 30, 2009 and 2008, and our investment balance in the proposed Palomar pipeline was $10.6 million and $9.3 million, respectively. Financial Corporation's assets include a non-controlling interest in the Kelso Beaver pipeline. The current balance in Palomar reflects our equity investment to date in a proposed 217-mile transmission pipeline. Net income from our other business segment for the three and six months ended June 30, 2009 was less than $0.1 million and $0.1 million, respectively, compared to $1.5 million and $1.8 million for the three and six months ended June 30, 2008, respectively. See Note 2.

Consolidated Operating Expenses

Operations and Maintenance

Three months ended June 30, 2009 compared to June 30, 2008:

Operations and maintenance expense was $30.2 million in 2009, compared to $25.8 million in 2008, an increase of $4.3 million or 17 percent. The major factors that contributed to the increase in operations and maintenance expense are:

- a $1.7 million increase in pension expense primarily due to lower returns on plan investments resulting from a decline in the market value of assets during 2008;
- a $1.0 million increase in technology expense primarily due to start up costs related to new systems;
- a $0.7 million increase from higher health care benefit expenses; and
- a $0.7 million increase in incentive bonus accruals due to improved operating results.

Six months ended June 30, 2009 compared to June 30, 2008:

Operations and maintenance expense was $64.1 million in 2009, compared to $54.3 million in 2008, an increase of $9.8 million or 18 percent. The major factors that contributed to the increase in operations and maintenance expense are:

- a $3.8 million increase in pension expense primarily due to lower returns on plan investments resulting from a decline in the market value of assets during 2008;
- a $1.4 million increase from higher health care benefit expenses;
- a $1.9 million increase in incentive bonus accruals due to improved operating results; and
- a $1.1 million increase in utility bad debt expense.

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Our bad debt expense ratio as a percent of revenues was 0.38 percent for the 12 months ended June 30, 2009, compared to 0.31 percent in the same period last year. Excluding customer refunds in June 2009, our bad debt expense as a percent of revenues was 0.36 percent for the 12 months ended June 30, 2009. Due to the weak economy and high unemployment rates, we are seeing an increase in delinquent balances and customers on payment plans. Partially helping our collection results are an increase in low income energy assistance funds for customers and a rate mechanism that covers the increase in bad debt expense tied to historically higher commodity costs. Under our PGA mechanism, billing rates are adjusted each year to recover the expected increase (or decrease) in bad debt expense due to the higher cost of natural gas. The revenue adjustment for bad debt expense is based on our average write-off rate over the last three years multiplied by the estimated increase in commodity costs. In the six months ended June 30, 2009, margin revenues increased by approximately $0.5 million to offset the expected increase in bad debt expense related to higher gas costs. Although we may experience a higher increase in bad debt expense this year, we believe much of the increase will be offset by the allowed rate increase under our PGA mechanism.

General Taxes

Three months ended June 30, 2009 compared to June 30, 2008:

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, decreased $0.2 million, or 2 percent, in the three months ended June 30, 2009 over the same period in 2008. Property taxes increased $0.3 million, or 7 percent, reflecting an increase in net utility plant and net non-utility property in service.

Six months ended June 30, 2009 compared to June 30, 2008:

For the six months ended June 30, 2009, general taxes increased $0.2 million, or 1 percent, compared to the same period in 2008. Property taxes increased $0.5 million, or 5 percent, reflecting an increase in net utility plant and net non-utility property in service.

We have been involved in litigation with the Oregon Department of Revenue (ODOR) over whether natural gas inventories and appliance inventories held for resale are required to be taxed as personal property. In November 2007, the Oregon Tax Court ruled in our favor stating that these inventories were exempt from property tax. However, the ODOR appealed the judgment to the Oregon Supreme Court in August 2008. If we are successful in this litigation, we would be entitled to a refund of over $5.0 million for property taxes paid on gas inventories beginning with the 2002-03 tax year and appliance inventories beginning with the 2005-06 tax year, plus accrued interest. Due to the uncertain outcome of the proceeding, we have not recorded the recovery of property taxes paid on gas inventories or appliance inventories to recognize the potential gain contingency.

Depreciation and Amortization

Depreciation and amortization expense decreased by $2.6 million and $4.8 million, or 14 percent and 13 percent, respectively, for the three and six months ended June 30, 2009, compared to the same periods in 2008. The lower expense reflects new depreciation rates approved by the OPUC and WUTC, effective January 1, 2009. The decrease in depreciation expense in 2009 is offset by a decrease in operating revenues of $6.5 million for the six months ended June 30, 2009. See "Regulatory Matters—Rate Mechanisms—Depreciation Study," above.

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Other Income and Expense – Net

The following table summarizes other income and expense – net by primary components:

Thousands	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Other income and expense - net:				
Gains from company-owned life insurance	$ 921	$ 519	$ 2,002	$ 978
Interest income	39	131	99	130
Income from equity investments	446	371	734	346
Net interest on deferred regulatory accounts	288	(176)	789	(343)
Other	(962)	1,095	(2,002)	1,002
Total other income and expense - net	$ 732	$ 1,940	$ 1,622	$ 2,113

Three months ended June 30, 2009 compared to June 30, 2008:

Other income and expense – net decreased $1.2 million, primarily due to a decrease in other non-operating income as 2008 included a gain from the sale of our investment in a Boeing aircraft in the second quarter. This was partially offset by additional income from company-owned life insurance and interest income from our deferred regulatory accounts.

Six months ended June 30, 2009 compared to June 30, 2008:

Other income and expense – net decreased $0.5 million, primarily due to a decrease in other non-operating income as 2008 included a gain from the sale of our aircraft investment. This was partially offset by additional income from company-owned life insurance and interest income from our deferred regulatory accounts.

Interest Charges – Net of Amounts Capitalized

Interest charges – net of amounts capitalized increased $1.1 million and $1.0 million, or 12 percent and 6 percent, in the three and six months ended June 30, 2009 compared to the same period in 2008, respectively. The increase is primarily due to higher balances on short-term debt and long-term debt outstanding, including the $75 million of 5.37 percent MTNs issued in March 2009 (see Note 5).

Income Tax Expense

Income tax expense totaled $30.3 million in the six months ended June 30, 2009 compared to $27.5 million in the same period of 2008. The effective tax rate was 37.5 percent in 2009 compared to 37.2 percent in 2008. The slightly higher income tax rate in 2009 is primarily due to higher taxable income. For additional factors impacting our effective tax rate, see Note 12.

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Financial Condition

Capital Structure

Our goal is to maintain a strong consolidated capital structure, generally consisting of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources also are used to fund long-term debt redemption requirements and short-term commercial paper maturities (see "Liquidity and Capital Resources," below, and Note 5). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	June 30, 2009	June 30, 2008	Dec. 31, 2008
Common stock equity	49.2%	51.6%	45.3%
Long-term debt	44.0%	42.4%	36.8%
Short-term debt, including current maturities of long-term debt	6.8%	6.0%	17.9%
Total	100.0%	100.0%	100.0%

Liquidity and Capital Resources

At June 30, 2009, we had $31.1 million of cash and cash equivalents compared to $5.2 million at June 30, 2008. In order to have sufficient liquidity during these uncertain times, we are continuing to maintain higher cash balances and plenty of short-term borrowing capacity while refinancing short-term debt balances in a low long-term fixed rate environment. Short-term liquidity is provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, committed credit facilities, including multi-year commitments which are primarily used to back-up commercial paper (see "Credit Agreement," below), an ability to borrow from cash surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt and for general corporate purposes. In March 2009, we issued $75 million of secured medium-term notes (MTNs) at 5.37 percent, with a maturity date of February 1, 2020. On July 9, 2009, we issued $50 million of secured MTNs at 3.95 percent, with a maturity date of July 15, 2014.

Our current senior secured long-term debt ratings are AA- and A1 from Standard & Poor's (S&P) and Moody's Investors Service (Moody's), respectively, as Moody's upgraded our rating from A2 to A1 on August 3, 2009. Our short-term debt ratings are A-1+ and P-1 from S&P and Moody's, respectively. The capital markets, including the commercial paper market, have experienced significant volatility and tight credit conditions over the last nine months, as reflected by increased credit spreads and limited access to new financing. With our current debt ratings we have been able to issue commercial paper notes at attractive rates and have not needed to borrow from our $250 million back-up facility. In the event that we are not able to issue commercial paper due to market conditions, we expect that our liquidity needs can be met by using cash balances or drawing upon our committed credit facility (see "Credit Agreement," below). We also have a universal shelf registration statement filed with the Securities and Exchange Commission for the issuance of secured and unsecured debt or equity securities, market conditions permitting. After giving effect to the issuance of $50 million of secured MTNs in July, 2009, we had OPUC approval to issue up to $175 million of additional MTNs under the shelf registration statement.

Our senior unsecured long-term debt ratings are A+ and A3 from S&P and Moody's, respectively. In the event that our senior unsecured long-term debt credit ratings are downgraded, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional costs and may trigger significant increases in short-term borrowings.

Based on our current credit ratings, our recent experience issuing commercial paper, our current cash reserves, the availability and size of our committed credit facilities and other liquidity resources, and our ability to issue long-term debt and equity securities under our universal shelf registration, we believe our liquidity is sufficient to meet our anticipated near-term cash requirements, including the contractual obligations and investing and financing activities discussed below.

Off-Balance Sheet Arrangements

Except for certain lease and purchase commitments (see "Contractual Obligations," below), we have no material off-balance sheet financing arrangements.

Contractual Obligations

Since December 31, 2008, our other purchase commitments increased $14 million from additional purchase commitments made in the ordinary course of business. Our contractual obligations also increased from our issuances of $75 million of secured MTNs at 5.37 percent in March 2009 and $50 million of secured MTNs at 3.95 percent in July 2009. Our contractual obligations at December 31, 2008 are described in Part II, Item 7., "Financial Condition—Liquidity and Capital Resources—Contractual Obligations," in the 2008 Form 10-K.

On July 13, 2009, our union employees who are members of the Office and Professional Employees International Union (OPEIU), Local No. 11, ratified a new five-year labor agreement called the Joint Accord. The agreement includes a 2.3 percent average wage increase effective June 1, 2009, and a scheduled one percent wage increase each year thereafter with the potential for up to an additional two percent based per year based on wage inflation and other factors, and it maintains competitive health benefits while keeping cost increases to the same level as the annual wage increases. The Joint Accord also provides increased job flexibility for the company along with an ability to use short-term unpaid leave to temporarily adjust the workforce without layoffs. It also continues the company's defined benefit retirement plan for existing employees, but closes the plan to new employees hired after December 31, 2009.

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Commercial Paper and Other Short-Term Loans

Our primary source of short-term liquidity is from internal cash flows and the sale of commercial paper notes payable. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt may be used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities (see "Credit Agreement," below). Our commercial paper program did not experience any liquidity disruptions as a result of the credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs last year. At June 30, 2009 and 2008, we had commercial paper outstanding of $79.8 million and $67.7 million, respectively. This year's outstanding balances were higher than last year's primarily due to higher balances in gas inventories.

In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million that expires on September 30, 2009. As of June 30, 2009, Gill Ranch had borrowed loan proceeds of $10.8 million. The effective interest rate on Gill Ranch's credit facility is 0.8 percent.

Credit Agreement

We have a syndicated line of credit for unsecured revolving loans totaling $250 million available and committed for a term expiring on May 31, 2012, with $210 million of that commitment amount extended through May 31, 2013. The lenders under our syndicated credit agreement are major financial institutions with committed balances and investment grade credit ratings as of June 30, 2009 as follows:

Lender rating, by category	Amount Committed (in $000's)
AAA/Aaa	$ -
AA/Aa	230,000
A/A	20,000
BBB/Baa	-
Total	$ 250,000

Based on current credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, including a review of capital ratios, credit default swap spreads and credit ratings, we believe the risk of lender default is minimal.

Pursuant to the terms of our credit agreement for the syndicated line of credit, we may request maturity extensions for additional one-year periods subject to lender approval. We extended commitments with six of the seven lenders under the syndicated credit agreement, with commitments totaling $210 million, to May 31, 2013. The credit agreement also allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million, and to replace any lenders who decline to extend the terms of the credit agreement. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. Any principal and unpaid interest owed on borrowings under the credit agreement is due and payable on or before the expiration date. There were no outstanding balances under this credit agreement at June 30, 2009 and

2008. The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at June 30, 2009 and 2008, with consolidated indebtedness to total capitalization ratios of 50.8 percent and 48.4 percent, respectively.

The credit agreement also requires that we maintain credit ratings with S&P and Moody's and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. However, a change in our debt rating below BBB- or Baa3 would require additional approval from the OPUC prior to issuance of debt, and interest rates on any loans outstanding under the credit agreement are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreement when ratings are changed (see "Credit Ratings," below).

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Credit Ratings

The following table summarizes our current debt credit ratings from S&P and Moody's:

	S&P	Moody's
Commercial paper (short-term debt)	A-1+	P-1
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	A+	A3
Ratings outlook	Negative	Stable

In August 2009, Moody's upgraded our senior secured long-term debt ratings from A2 to A1. Both rating agencies have assigned investment grade credit ratings to NW Natural. These credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

In July 2008, we redeemed $5 million of secured 6.50 percent MTNs at maturity. For long-term debt maturing over the next five years, see Part II, Item 7., "Results of Operations—Financial Condition—Contractual Obligations," in our 2008 Form 10-K.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements and other cash and non-cash adjustments to operating results. In the six months ended June 30, 2009, cash flow from operating activities, excluding working capital changes, increased $2.9 million compared to the same period in 2008. Cash flow from working capital changes in the six months ended June 30, 2009 increased by $58.8 million compared to the same period in 2008. The overall change in cash flow from operating activities was an increase of $61.7 million. The significant factors contributing to changes in the cash flow between the six months ended June 30, 2009 compared to the same period of 2008 are as follows:

- an increase in cash of $42.5 million from deferred gas costs reflecting actual gas costs lower than gas costs embedded in rates in 2009;
- an increase in cash of $56.9 million from reductions in accounts receivable and accrued unbilled revenue primarily due to customer refunds in June 2009 and higher balances in accounts receivable and accrued unbilled revenue balances at year end 2008 compared to 2007 because of colder weather at the end of 2008;
- a decrease in cash of $19.9 million from gas inventories due to lower withdrawals from storage because of warmer weather in 2009 compared to 2008;
- a decrease in cash of $25.0 million from our pension contribution in April 2009 to reduce our unfunded liability;
- a decrease in cash of $10.1 million from the loss realized on the settlement of our interest rate hedge (see Note 10); and
- an increase in cash of $20.8 million from income taxes receivable which we received as a cash refund of $10.3 million in June 2009 and the balance as a reduction to income taxes paid.

In June 2009, we refunded an aggregate $35.3 million to our Oregon and Washington customers for the customers' shares of accumulated gas cost savings from November 1, 2008 through March 31, 2009 due to lower gas prices. This reduction in cash was more than offset by the lower gas costs and other factors described above.

In addition to actual changes in cash flow discussed above, we filed an application with the Internal Revenue Service (IRS) in December 2008, requesting a change in tax accounting method in connection with our routine repair and maintenance costs for gas pipelines that are currently being capitalized and depreciated for book purposes. We anticipate that the IRS will consent to this change during the third quarter of 2009. If approved, then we will file a claim for a tax deduction and record current tax benefits and a deferred tax liability, which will result in a refund of taxes paid and an increase in cash flow. We estimate the tax refund amount for 2009 and prior years to be in excess of $15 million related to routine repair and maintenance costs.

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Investing Activities

Cash used in investing activities for the six months ended June 30, 2009 totaled $58.6 million, up from $46.7 million for the same period in 2008. Cash requirements for the acquisition and construction of utility plant were $44.1 million in six months ended June 30, 2009, up $2.8 million from $41.3 million for the same period in 2008. The increase was primarily due to automated meter reading project costs, which were partially offset by lower costs for new construction and system expansion.

Cash requirements for investments in non-utility property were $10.3 million in the six months ended June 30, 2009, primarily related to investments in Gill Ranch, compared to $5.1 million in 2008. In the six months ended June 30, 2008 we sold our investment in a Boeing 737-300 aircraft for proceeds of $6.8 million. Cash requirements for other non-utility investments were a net $5.0 million, compared to $7.3 million last year. In the six months ended June 30, 2009, cash used in other investing activities increased $2.3 million, primarily due to a $5.0 million increase in our restricted cash investment in Gill Ranch. This was partially offset by a net distribution from Palomar of $4.3 million, compared to contributions of $3.0 million to Palomar for the same period in 2008.

In 2009, utility capital expenditures are estimated to be between $100 and $110 million, and non-utility capital investments are expected to be between $50 and $70 million for business development projects that are currently in process (see “Strategic Opportunities,” above).

Over the five-year period 2009 through 2013, utility construction expenditures are estimated at between $450 and $500 million. The estimated level of capital expenditures over the next five years reflects customer growth, utility storage development at Mist, AMR, technology improvements and utility system improvements, including requirements under the Pipeline Safety Improvement Act of 2002. Most of the required funds are expected to be internally generated over the five-year period and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing (see Part II, Item 7., “Financial Condition—Cash Flows—Investing Activities,” in the 2008 Form 10-K).

Our share of the total project cost of Gill Ranch is estimated to be between $160 million and $180 million. As of June 30, 2009, we have spent $23.9 million.

In 2009 and 2010, Palomar will continue to work on the planning and permitting phase of the Palomar pipeline project. The total cost for planning and permitting is estimated to be between $40 million and $50 million, of which our ownership interest is 50 percent. As of June 30, 2009, we had a net equity investment of $10.6 million in this project. The total cost estimate for the entire 217-mile pipeline, if constructed, is estimated to be between $750 million and $800 million, with our current 50 percent share estimated at between $375 million and $400 million. See "Strategic Opportunities—Pipeline Diversification," above.

The Palomar pipeline project includes both an east and west segment. Palomar intends to proceed with the construction of the west segment of the pipeline if an LNG terminal is developed. However, the development of LNG terminals along the Columbia River may or may not proceed, dependent upon a variety of factors, including obtaining state and federal permits, securing acceptable financing and economic conditions. Palomar had executed precedent agreements whereby a significant majority of the pipeline capacity was committed to one shipper. In April 2009, Palomar and that shipper replaced their existing precedent agreement with a new agreement for the same amount of capacity and Palomar received $15.8 million of cash proceeds which had supported the shipper's obligations under the prior agreement. The cash proceeds received were applied against project costs. Under the new precedent agreement the shipper provided, and Palomar accepted, a new form of credit support. The new credit support is expected to support a portion of the ongoing planning and permitting costs as the project develops. In addition, Palomar has the right to request additional credit support from the shipper at future stages of the project development. A failure to provide acceptable ongoing credit support to meet such shipper's obligations may result in Palomar reassessing its commitment to the development of the west segment.

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Based on an ongoing review of the Palomar pipeline project, and continuing interest expressed by this shipper, and other potential shippers, PGH determined that the Palomar project was still viable, especially the east segment. As of May 1, 2009, Palomar has binding precedent agreements with two shippers, including our own utility, which represents a majority of the current design capacity on the pipeline. We will continue to manage project risks, evaluate project costs and assess the fair value of our investment on a quarterly basis, including a valuation of the available credit support. Further, during 2009 and 2010, PGH will continue to evaluate market conditions and project status to determine if and when to proceed with construction of all or some portion of the project. See Part I, Item 1A., "Risk Factors," in the 2008 Form 10-K.

Financing Activities

Cash used in financing activities in the six months ended June 30, 2009 totaled $117.0 million, up from $92.3 million cash used in the same period of 2008. Our short-term debt balances decreased by $170.2 million in the six months ended June 30, 2009 compared to a decrease of $75.4 million for the same period in 2008. In March 2009, we issued $75 million of MTNs at 5.37 percent, the proceeds of which were primarily used to reduce short-term debt balances and for general corporate purposes. No shares were purchased under our common stock repurchase program, and no long-term debt was redeemed in the six months ended June 30, 2009 and 2008.

Pension Funding Status

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established new funding requirements for defined benefit plans. The Act establishes a 100 percent funding target for plan years beginning after December 31, 2008. Our qualified defined benefit pension plans were underfunded by $98.4 million at December 31, 2008. In April 2009, we contributed $25 million. We anticipate no further funding requirements for our qualified plans in 2009, but we may make additional contributions later this year that could bring our total contributions in 2009 up to $40 million. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Note 7, and Part II, Item 7., “Financial Condition—Pension Cost and Funding Status of Qualified Retirement Plans,” and Part II, Item 8., Note 7, “Pension and Other Postretirement Benefits,” in the 2008 Form 10-K.

We also contribute to a multiemployer pension plan pursuant to our collective bargaining agreement. Our total contribution to the Western States Plan in 2008 amounted to $0.4 million. We made contributions totaling $0.2 million to the Western States Plan for both the six months ended June 30, 2009 and 2008. See Note 7 for further discussion.

Ratios of Earnings to Fixed Charges

For the six and twelve months ended June 30, 2009 and the twelve months ended December 31, 2008, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 4.96, 3.87 and 3.76, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. Because a significant part of our business is of a seasonal nature, the ratios for the interim periods are not necessarily indicative of the results for a full year.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, “Accounting for Contingencies” (see Part II, Item 7., “Application of Critical Accounting Policies and Estimates,” in the 2008 Form 10-K). At June 30, 2009, we had a regulatory asset of $70.1 million for environmental costs, which includes $33.7 million of total paid expenditures to date, $28.7 million for additional environmental costs expected to be paid in the future and accrued interest of $7.7 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 11.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price risk, interest rate risk, foreign currency risk, credit risk and weather risk (see Part I, Item 1A., "Risk Factors," and Part II, Item 7A. "Quantitative and Qualitative Disclosures about Market Risk," in the 2008 Form 10-K). The following are updates to certain of these market risks:

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion, potential market speculation and other factors that affect short-term supply and demand. Commodity-swap and option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed, capped or discounted prices. These financial hedge contracts are generally included in our annual PGA filing for cost recovery, subject to a regulatory prudence review. At June 30, 2009 and 2008, notional amounts under these financial hedge contracts totaled $308.4 million and $332.6 million, respectively. If all of the commodity-based financial hedge contracts had been settled on June 30, 2009, a loss of about $72.9 million would have been realized and recorded to a deferred regulatory account (see Note 10). We regularly monitor and manage the financial exposure and liquidity risk of our financial hedge contracts under the direction of our Gas Acquisition Strategies and Policies Committee, which consists of senior management with Audit Committee oversight. Based on the existing open interest in the contracts held, we believe financial exposure to be minimal and existing contracts to be liquid. All of our financial hedge contracts mature on or before October 31, 2012. The $72.9 million unrealized loss is an estimate of future cash flows based on forward market prices that are expected to be paid as follows: $59.4 million in the next 12 months and $13.5 million thereafter. The amount realized will change based on market prices at the time contract settlements are fixed.

Credit Risk

Credit exposure to financial derivative counterparties. Based on estimated fair value at June 30, 2009, our credit exposure relating to commodity hedge contracts reflected an amount we owed of $72.9 million to our financial derivative counterparties. Our financial derivatives policy requires counterparties to have a certain minimum investment-grade credit rating at the time the derivative instrument is entered into, and specific limits on the contract amount and duration based on each counterparty's credit rating. Some counterparties were downgraded but continue to maintain investment grade ratings (see table below). Due to current market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require letters of credit or guarantees as circumstances warrant. Our derivative credit risk exposure, which reflects amounts that financial derivative counterparties owe to us, is minimal and all outstanding contracts at June 30, 2009 expire or are expected to settle on or before October 31, 2012.

The following table summarizes our credit exposure, based on estimated fair value, and the corresponding counterparty credit ratings for our unrealized fair value gains and losses. The table uses credit ratings from S&P and Moody's, reflecting the higher of the S&P or Moody's rating or a middle rating if the entity is split-rated with more than one rating level difference:

Thousands	June 30, 2009	June 30, 2008	Dec. 31, 2008
AAA/Aaa	$ -	$ 8,906	$ (16,827)

AA/Aa		(65,060)		45,863		(122,287)
A/A		(7,821)		6,013		(12,006)
BBB/Baa		-		-		-
Total	$	(72,881)	$	60,782	$	(151,120)

To mitigate the credit risk of financial derivatives we have master netting arrangements with our counterparties that provide for making or receiving net cash settlements. Generally, transactions of the same type in the same currency that have a settlement on the same day with a single counterparty are netted and a single payment is delivered or received depending on which party is due funds.

Additionally we have master contracts in place with each of our derivative counterparties that usually include provisions for the posting or calling of collateral. Generally we can obtain cash or marketable securities as collateral with one day's notice. We use various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded that the current liquidity risk from collateral calls is not material. Our derivative credit exposure is primarily with investment grade counterparties rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk.

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Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

We are subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, we do not expect that the ultimate disposition of any of these matters will have a material adverse effect on our financial condition, results of operations or cash flows.

For a discussion of certain pending legal proceedings, see Note 11.

Item 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, "Item 1A. Risk Factors," in our 2008 Form 10-K. In addition to the other information set forth in this report, you should carefully consider those risk factors, which could materially affect our business, financial condition or results of operations. The risks described in the 2008 Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially affect our financial condition, results of operations or cash flows.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table provides information about purchases by us during the quarter ended June 30, 2009 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (2)
Balance forward			2,124,528	$ 16,732,648
04/01/09 - 04/30/09	1,792	$ 41.89	-	-
05/01/09 - 05/31/09	22,813	$ 41.47	-	-
06/01/09 - 06/30/09	3,156	$ 44.46	-	-
Total	27,761	$ 41.84	2,124,528	$ 16,732,648

(1) During the three months ended June 30, 2009, 26,921 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 840 shares of our common stock were purchased on the open market during the quarter to meet the requirements of our share-based programs. During the three months ended June 30, 2009, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2010 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the three months ended June 30, 2009, no shares of our common stock were purchased pursuant to this program. Since the program's inception in 2000 we have repurchased 2.1 million shares of common stock at a total cost of $83.3 million.

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

NW Natural's Annual Meeting of Shareholders was held in Portland, Oregon on May 28, 2009. At the meeting, four director-nominees were elected, as follows:

Director	Class	Term Expiring	Votes For	Votes Withheld
Timothy P. Boyle	I	2012	23,053,175	387,132
Mark S. Dodson	I	2012	22,993,053	447,254
George J. Puentes	I	2012	23,072,614	367,693
Gregg S. Kantor	III	2011	22,973,334	466,973

The other seven directors whose terms of office as directors continued after the Annual Meeting are: Martha L. "Stormy" Byorum, John D. Carter, C. Scott Gibson, Tod R. Hamachek, Jane J. Peverett, Kenneth Thrasher, and Russell F. Tromley.

The following matters also were acted upon at the meeting:

The ratification of the Audit Committee's appointment of PricewaterhouseCoopers LLP as NW Natural's independent registered public accounting firm for the year 2009 was approved by the following vote:

For	Against	Abstain
23,049,448	276,959	113,898

No other matters were acted upon at the meeting.

Item 5. OTHER INFORMATION

On July 20, 2009, the governor of Oregon signed House Bill 3405 establishing increases in the state income tax for corporations. The corporate income tax rate in Oregon for 2010 will increase from 6.6 percent to 7.9 percent for corporations with taxable income over $250,000. For tax years 2011 and 2012, the income tax rate will decrease to 7.6 percent, and for years after 2012 the tax rate will return to the current 6.6 percent, except for corporations with taxable income over $10 million the tax rate will remain at 7.6 percent. The new tax rates are retroactive to January 1, 2009. We are in the process of re-measuring our deferred income tax assets and liabilities in accordance with SFAS No. 109 "Accounting for Income Taxes," and determining the accounting recognition for utility regulation in accordance with SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation." With respect to our regulated utility, we expect to record a regulatory asset for the tax effect of the corporate income tax rate changes in the third quarter of 2009. With respect to our non-regulated business segments, we anticipate that we will need to record an immaterial charge to income tax expense for the impact on those earnings from the corporate tax rate change.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

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SIGNATURE

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.

NORTHWEST NATURAL GAS COMPANY
(Registrant)

Dated: August 6, 2009

/s/ Stephen P. Feltz
Stephen P. Feltz
Principal Accounting Officer
Treasurer and Controller

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NORTHWEST NATURAL GAS COMPANY

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To
Quarterly Report on Form 10-Q
For Quarter Ended
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