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, 2010

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 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] 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. (Check one):

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [ ]
(Do not check if a 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 30, 2010, 26,576,278 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, 2010

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

Table of Contents

Forward-Looking Statements

This report contains “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as “anticipates,” “intends,” “plans,” “seeks,” “believes,” “estimates,” “expects” and similar references to future periods. Examples of forward-looking statements include, but are not limited to statements regarding the following:

- plans;
- objectives;
- goals;
- strategies;
- future events or performance;
- trends;
- cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- financial positions;
- development of projects;
- competition;
- exploration of new gas supplies;
- the benefits of liquefied natural gas;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- impacts of new laws, regulations and financial accounting standards;
- outcomes of litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- adequacy of, and shift in, mix of gas supplies;
- adequacy of regulatory deferrals; and
- environmental, regulatory and insurance costs and recovery.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We caution you therefore against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2009 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.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

1

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands, except per share amounts	2010	2009	2010	2009
Operating revenues:				
Gross operating revenues	$162,365	$149,060	$448,894	$586,415
Less: Cost of sales	86,301	79,388	234,862	363,562
Revenue taxes	3,871	3,753	10,913	14,295
Net operating revenues	72,193	65,919	203,119	208,558
Operating expenses:				
Operations and maintenance	28,406	30,171	59,072	64,126
General taxes	7,543	6,572	10,792	15,063
Depreciation and amortization	16,026	15,365	31,927	30,887
Total operating expenses	51,975	52,108	101,791	110,076
Income from operations	20,218	13,811	101,328	98,482
Other income and expense - net	1,613	732	4,636	1,622
Interest expense - net	10,617	10,006	21,106	19,376
Income before income taxes	11,214	4,537	84,858	80,728
Income tax expense	4,326	1,451	34,362	30,279
Net income	$6,888	$3,086	$50,496	$50,449
Average common shares outstanding:				
Basic	26,569	26,506	26,553	26,504
Diluted	26,641	26,607	26,621	26,603
Earnings per share of common stock:				
Basic	$0.26	$0.12	$1.90	$1.90
Diluted	$0.26	$0.12	$1.90	$1.90
Dividends per share of common stock	$0.415	$0.395	$0.83	$0.79

See Notes to Consolidated Financial Statements

Table of Contents

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

Thousands	June 30, 2010	June 30, 2009	December 31, 2009
Assets:			
Current assets:			
Cash and cash equivalents	$7,142	$31,107	$8,432
Restricted cash	929	15,822	35,543
Accounts receivable	42,781	26,779	77,438
Accrued unbilled revenue	16,419	18,122	71,230
Allowance for uncollectible accounts	(2,577)	(3,520)	(3,125)
Regulatory assets	56,804	89,179	29,954
Derivative assets	1,495	5,293	6,504
Inventories:			
Gas	68,735	69,183	71,672
Materials and supplies	8,714	9,681	9,285
Other current assets	9,823	10,766	21,302
Total current assets	210,265	272,412	328,235
Non-current assets:			
Property, plant and equipment	2,482,826	2,263,325	2,362,734
Less accumulated depreciation	710,732	679,977	692,600
Total property, plant and equipment - net	1,772,094	1,583,348	1,670,134
Regulatory assets	329,197	270,044	316,536
Derivative assets	453	289	843
Other investments	68,393	62,315	67,365
Other non-current assets	15,159	16,103	16,139
Total non-current assets	2,185,296	1,932,099	2,071,017
Total assets	$2,395,561	$2,204,511	$2,399,252

See Notes to Consolidated Financial Statements

Table of Contents

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

Thousands	June 30, 2010	June 30, 2009	December 31, 2009
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; 100,000 shares authorized; 26,576, 26,513 and 26,533 shares outstanding at June 30, 2010 and 2009 and December 31, 2009, respectively	$339,394	$336,001	$337,361
Retained earnings	357,173	325,506	328,712
Accumulated other comprehensive income (loss)	(5,772)	(4,260)	(5,968)
Total stockholders' equity	690,795	657,247	660,105
Long-term debt	591,700	587,000	601,700
Total capitalization	1,282,495	1,244,247	1,261,805
Current liabilities:			
Short-term debt	106,875	90,610	102,000
Current maturities of long-term debt	45,000	-	35,000
Accounts payable	81,675	50,055	123,729
Taxes accrued	13,008	10,807	21,037
Interest accrued	5,397	3,876	5,435
Regulatory liabilities	29,524	30,789	46,628
Derivative liabilities	34,463	70,052	19,643
Other current liabilities	31,900	33,343	39,097
Total current liabilities	347,842	289,532	392,569
Deferred credits and other liabilities:			
Deferred tax liabilities	316,152	273,384	300,898
Regulatory liabilities	251,585	238,264	248,622
Pension and other postretirement benefit liabilities	120,185	116,844	127,687
Derivative liabilities	16,917	8,844	3,193
Other non-current liabilities	60,385	33,396	64,478
Total deferred credits and other liabilities	765,224	670,732	744,878
Commitments and contingencies (see Note 11)	-	-	-
Total capitalization and liabilities	$2,395,561	$2,204,511	$2,399,252

See Notes to Consolidated Financial Statements

Table of Contents

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

Thousands	Six Months Ended June 30, 2010	2009
Operating activities:		
Net income	$50,496	$50,449
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	31,927	30,887
Undistributed earnings from equity investments	(728)	(734)
Non-cash expenses related to qualified defined benefit pension plans	4,131	4,848
Contributions to qualified defined benefit pension plans	(10,000)	(25,000)
Deferred environmental costs	(4,286)	(5,227)
Settlement of interest rate hedge	-	(10,096)
Other	(1,264)	(2,002)
Changes in assets and liabilities:		
Receivables	88,920	141,173
Inventories	3,508	17,203
Income taxes receivable	-	20,811
Accounts payable	(39,323)	(44,177)
Accrued interest	(38)	1,091
Accrued taxes	(8,029)	(1,648)
Deferred gas savings - net	(18,336)	15,616
Deferred tax liabilities	15,979	15,405
Other - net	(8,694)	(8,786)
Cash provided by operating activities	104,263	199,813
Investing activities:		
Capital expenditures	(125,966)	(54,428)
Restricted cash	34,614	(10,803)
Other	964	6,587
Cash used in investing activities	(90,388)	(58,644)
Financing activities:		
Common stock issued - net	1,613	(720)
Long-term debt issued	-	75,000
Change in short-term debt	4,875	(170,241)
Cash dividend payments on common stock	(22,035)	(20,937)
Other	382	(80)
Cash used in financing activities	(15,165)	(116,978)
Increase (decrease) in cash and cash equivalents	(1,290)	24,191
Cash and cash equivalents - beginning of period	8,432	6,916
Cash and cash equivalents - end of period	$7,142	$31,107
Supplemental disclosure of cash flow information:		
Interest paid	$20,370	$17,828
Income taxes paid	$21,100	$1,500

See Notes to Consolidated Financial Statements

Table of Contents

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

1. Summary of Significant Accounting Policies

Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), primarily consisting of our regulated gas distribution business and our gas storage business, which includes our wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), NW Natural Gas Storage, LLC (NW Gas Storage), a wholly-owned subsidiary of our subsidiary NW Natural Energy, LLC, and other investments and business activities, which primarily consist of our wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and an equity investment in Palomar Gas Holdings, LLC (PGH) that is developing a proposed natural gas transmission pipeline through its wholly-owned subsidiary Palomar Gas Transmission LLC (Palomar) (see Note 2). Investments in corporate joint ventures and partnerships in which we are not the primary beneficiary are accounted for by the equity method or the cost method.

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 business and other non-utility investments and business activities (see Note 2). Intercompany accounts and transactions have been eliminated, except for transactions required to be included under regulatory accounting standards to reflect the effect of such 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 2009 Annual Report on Form 10-K (2009 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.

Our significant accounting policies are described in Note 1 of the 2009 Form 10-K. There were no material changes to those accounting policies during the six months ended June 30, 2010. See below for a further discussion of newly adopted standards and recent accounting pronouncements. We do not have any subsequent events to report.

Certain prior year balances on our consolidated financial statements have been combined or reclassified to conform with the current presentation. These changes had no impact on our prior year's consolidated results of operations and no material impact on financial condition or cash flows.

Table of Contents

Industry Regulation

At June 30, 2010 and 2009 and at December 31, 2009, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		
Thousands	June 30, 2010	June 30, 2009	December 31, 2009
Regulatory assets:			
Unrealized loss on non-trading derivatives(1)	$34,463	$70,052	$19,643
Pension and other postretirement benefit obligations(2)	7,502	8,074	7,502
Other(3)	14,839	11,053	2,809
Total regulatory assets	$56,804	$89,179	$29,954
Regulatory liabilities:			
Gas costs payable	$23,416	$19,010	$37,055
Unrealized gain on non-trading derivatives(1)	1,495	5,293	6,504
Other(3)	4,613	6,486	3,069
Total regulatory liabilities	$29,524	$30,789	$46,628

	Non-Current		
Thousands	June 30, 2010	June 30, 2009	December 31, 2009
Regulatory assets:			
Unrealized loss on non-trading derivatives(1)	$16,917	$8,844	$3,193
Income tax asset	75,515	70,096	76,240
Pension and other postretirement benefit obligations(2)	106,089	109,833	109,932
Environmental costs - paid(4)	52,577	41,362	46,204
Environmental costs - accrued but not yet paid(4)	56,747	28,689	59,844
Other(3)	21,352	11,220	21,123
Total regulatory assets	$329,197	$270,044	$316,536
Regulatory liabilities:			
Gas costs payable	$2,218	$3,758	$6,915
Unrealized gain on non-trading derivatives(1)	453	289	843
Accrued asset removal costs	246,839	231,880	238,757
Other(3)	2,075	2,337	2,107
Total regulatory liabilities	$251,585	$238,264	$248,622

(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 Purchased Gas Adjustment mechanism.

(2) Certain 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 6).

(3) 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.

(4)

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.

Table of Contents

New Accounting Standards

Adopted Standards

Variable Interest Entity. Effective January 1, 2010, we adopted the amended authoritative guidance on variable interest entities (VIE). This guidance requires a continuing analysis to determine whether an entity has a controlling financial interest and whether it is the primary beneficiary. As the primary beneficiary with a controlling financial interest we would be required to consolidate the VIE in our financial statements. The guidance defines the primary beneficiary 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 VIE.

Although we do have an ownership interest in PGH, which is the entity that owns Palomar and is a VIE, we are not the primary beneficiary (see Note 8) and therefore the adoption of this standard has not had a material effect on our financial condition, results of operations or cash flows; however, if we are required to consolidate PGH or other VIEs that may be acquired in future periods, it could have a material impact on our financial statements (see Note 8).

Recent Accounting Pronouncements

Fair Value Disclosures. In January 2010, the Financial Accounting Standards Board issued authoritative guidance on new fair value measurements and disclosures. This guidance requires additional disclosures for fair value measurements that use significant assumptions not observable in active markets (i.e. level 3 valuations) including a rollforward schedule. These changes are effective for periods beginning after December 15, 2010; however, we elected to early adopt these disclosure requirements, as shown in Note 7 of our 2009 Form 10-K. The adoption of this standard did not have, and is not expected to have, a material effect on our financial statement disclosures.

Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands, except per share amounts	2010	2009	2010	2009
Net income	$6,888	$3,086	$50,496	$50,449
Average common shares outstanding - basic	26,569	26,506	26,553	26,504
Additional shares for stock-based compensation plans	72	101	68	99
Average common shares outstanding - diluted	26,641	26,607	26,621	26,603
Earnings per share of common stock - basic	$0.26	$0.12	$1.90	$1.90
Earnings per share of common stock - diluted	$0.26	$0.12	$1.90	$1.90

For the three months ended June 30, 2010 and 2009, 5,052 and 6,228 common share equivalents, respectively, were excluded from the calculation of diluted earnings per share because the effect of these additional shares on the net income for both periods would have been anti-dilutive. For the six months ended June 30, 2010 and 2009, 1,364 and

5,143 common share equivalents, respectively, were excluded from the calculation of diluted earnings per share because the effect of these shares would have been anti-dilutive.

Table of Contents

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 one 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 NW Gas Storage, Gill Ranch and a portion of the gas storage services related to our Mist underground storage facility in Oregon. Our "other" segment includes our equity investment in PGH to develop the Palomar project and Financial Corporation. For further discussion of our segments, see Note 2 in our 2009 Form 10-K.

NW Gas Storage was recently formed to manage our gas storage operations, including Gill Ranch. NW Gas Storage commenced operations during the second quarter of 2010 and was not operational during 2009.

The following table presents information about the reportable segments for the three and six months ended June 30, 2010 and 2009. Inter-segment transactions are insignificant.

	Three Months Ended June 30,			
Thousands	Utility	Gas Storage	Other	Total
2010				
Net operating revenues	$66,939	$5,206	$48	$72,193
Depreciation and amortization	15,691	335	-	16,026
Income from operations	16,271	3,925	22	20,218
Net income	4,641	2,122	125	6,888
2009				
Net operating revenues	$60,064	$5,825	$30	$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

	Six Months Ended June 30,			
Thousands	Utility	Gas Storage	Other	Total
2010				
Net operating revenues	$192,412	$10,617	$90	$203,119
Depreciation and amortization	31,257	670	-	31,927
Income from operations	92,853	8,436	39	101,328
Net income	45,533	4,623	340	50,496
Total assets at June 30, 2010	2,143,138	229,919	22,504	2,395,561
2009				
Net operating revenues	$198,158	$10,325	$75	$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
Total assets at Dec. 31, 2009	2,205,313	173,648	20,291	2,399,252

Table of Contents

3. Capital Stock

As of June 30, 2010, our common shares authorized were 100,000,000 and our outstanding shares were 26,576,278.

We have a share repurchase program for our common stock under which we may purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2011 to repurchase up to an aggregate of 2.8 million shares or up to $100 million. No shares of common stock were repurchased under this program during the six months ended June 30, 2010. Since inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

4. Stock-Based Compensation

We have several stock-based compensation plans, including a Long-Term Incentive Plan (LTIP), a Restated Stock Option Plan (Restated SOP) and an Employee Stock Purchase Plan. These plans are designed to promote stock ownership in NW Natural by employees and officers. For additional information on our stock-based compensation plans, see Part II, Item 8., Note 4, in the 2009 Form 10-K and current updates provided below.

Long-Term Incentive Plan. On February 24, 2010, 41,500 performance-based shares were granted under the LTIP, which include a market condition, based on target-level awards and a weighted-average grant date fair value of $25.64 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	$ 44.25
Performance term (in years)	3.0
Quarterly dividends paid per share	$ 0.415
Expected dividend yield	3.7 %
Dividend discount factor	0.8949

In February 2010, the Board approved a payout of performance-based stock awards for the 2007-09 award period. Shares of common stock were purchased on the open market to satisfy the approved awards.

Restated Stock Option Plan. On February 24, 2010, options to purchase 119,750 shares were granted under the Restated SOP, with an exercise price equal to the closing market price of $44.25 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 $6.36 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	2.3 %
Expected life (in years)	4.7
Expected market price volatility factor	23.2 %
Expected dividend yield	3.8 %
Forfeiture rate	3.2 %

As of June 30, 2010, there was $1.1 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2013.

Table of Contents

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

Cost of Long-Term Debt

Our long-term debt consists of medium-term notes (MTNs) that have maturity dates from 2010 through 2035, and have interest rates ranging from 3.95 percent to 9.05 percent with an average interest rate of 6.19 percent. For the six months ended June 30, 2010 we did not issue or redeem any secured MTNs. In March 2009, we issued $75 million of 5.37 percent secured MTNs due February 1, 2020, and in July 2009, we issued another $50 million of secured MTNs with an interest rate of 3.95 percent and a maturity of July 15, 2014. Proceeds from these MTNs were used to fund utility capital expenditures, to redeem utility short-term and long-term debt, and to provide utility working capital for general corporate purposes.

Fair Value of Long-Term Debt

The following table provides an estimate of the fair value of our long-term debt including current maturities of long-term debt, using market prices in effect on the valuation date. Because our debt outstanding does not trade in active markets, we used interest rates for outstanding debt issues that actively trade and have similar credit ratings, terms and remaining maturities to estimate fair value for our long-term debt issues.

	June 30,		December 31,
Thousands	2010	2009	2009
Carrying amount	$636,700	$587,000	$636,700
Estimated fair value	$728,172	$612,931	$707,755

Table of Contents

6. 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	2010	2009	2010	2009
Service cost	$1,773	$1,664	$156	$148
Interest cost	4,492	4,492	342	407
Expected return on plan assets	(4,563)	(3,994)	-	-
Amortization of loss	1,768	1,658	8	4
Amortization of prior service cost	204	305	49	49
Amortization of transition obligation	-	-	103	103
Net periodic benefit cost	3,674	4,125	658	711
Amount allocated to construction	(947)	(1,178)	(207)	(232)
Net amount charged to expense	$2,727	$2,947	$451	$479

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2010	2009	2010	2009
Service cost	$3,546	$3,327	$312	$295
Interest cost	8,983	8,984	685	813
Expected return on plan assets	(9,127)	(7,989)	-	-
Amortization of loss	3,536	3,317	15	8
Amortization of prior service cost	410	611	98	98
Amortization of transition obligation	-	-	206	206
Net periodic benefit cost	7,348	8,250	1,316	1,420
Amount allocated to construction	(1,900)	(2,356)	(415)	(464)
Net amount charged to expense	$5,448	$5,894	$901	$956

See Part II, Item 8., Note 7, in the 2009 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. As of January 1, 2010, the Western States Plan had an accumulated funding deficiency for the current plan year and remained in “critical status.” A plan is considered to be in critical status if its funded status is 65 percent or less. 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. We made contributions totaling $0.2 million to the Western States Plan for both the six months ended June 30, 2010 and 2009. The Western States Plan board of trustees imposed a 5 percent contribution surcharge to participating employers, including NW Natural, beginning in August 2009, which increased to a 10 percent contribution surcharge beginning January 2010. The board of trustees also adopted a rehabilitation plan that reduced benefit accrual rates and adjustable benefits for active employee participants and increased future employer contribution rates. These changes are expected to improve the funding status of the plan. Contribution surcharges above 10 percent will be assessed to employer participants, 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 current collective bargaining agreement, which became effective in July 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.

Table of Contents

Employer Pension Contributions

In February 2010, we made a $10 million cash contribution to our qualified defined benefit pension plans, portions of which were for the 2009 and 2010 plan years. We also continue to make cash contributions for our unfunded, non-qualified pension plans and other postretirement benefit plans. For more information see Part II, Item 8., Note 7, in the 2009 Form 10-K.

7. Income Tax

The effective income tax rate for the six months ended June 30, 2010 and 2009 varied from the combined federal and state statutory tax rates principally due to the following:

	June 30, 2010		2009	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state statutory income tax rate, net of federal tax benefit	4.8	%	3.8	%
Amortization of investment and energy tax credits	(0.4	)%	(0.5	)%
Differences required to be flowed-through by regulatory commissions	1.4	%	(0.1	)%
Gains on company and trust-owed life insurance	(0.4	)%	(0.9	)%
Other - net	0.1	%	0.2	%
Effective tax rate	40.5	%	37.5	%

The increase in our effective tax rate for the six months ended June 30, 2010 compared to the same period in 2009 was primarily due to the increase in the Oregon statutory tax rate from 6.6 percent to 7.9 percent and an increase in the amortization rate of our regulatory tax asset pursuant to a regulatory order effective November 1, 2009, which we largely recover in utility rates or through a regulatory adjustment for income taxes paid.

8. Property and Investments

Property

Property, plant and equipment – net consists of the following as of June 30, 2010 and 2009 and December 31, 2009:

Thousands	June 30, 2010	June 30, 2009	December 31, 2009
Utility plant in service	$2,218,660	$2,154,198	$2,188,176
Utility construction work in progress	30,086	24,431	27,936
Less utility accumulated depreciation	700,202	670,128	682,060
Utility plant - net	1,548,544	1,508,501	1,534,052
Non-utility plant in service	66,862	66,002	66,084
Non-utility construction work in progress	167,218	18,694	80,538
Less: accumulated depreciation	10,530	9,849	10,540
Non-utility plant - net	223,550	74,847	136,082
Total property, plant and equipment - net	$1,772,094	$1,583,348	$1,670,134

Table of Contents

Investments

Our other long-term investments include financial investments in life insurance policies, which are accounted for at fair value, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity or cost methods (see Note 1 above for the newly adopted standard on variable interest entities, and see Part II, Item 8., Note 9, in the 2009 Form 10-K for more detail on our investments).

Variable Interest Entities. PGH is a VIE owned 50 percent by us and 50 percent by Gas Transmission Northwest Corporation, an indirect wholly-owned subsidiary of TransCanada Corporation. PGH intends to develop a natural gas transmission pipeline in Oregon to serve our utility as well as the growing natural gas markets in Oregon and other parts of the Pacific Northwest, through its wholly-owned subsidiary Palomar. Palomar is a development stage entity. As of June 30, 2010, we updated our VIE analysis and determined that we are not the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations (see Note 1). Therefore, we account for our investment in PGH and the Palomar project under the equity method, and our equity investment balance at June 30, 2010 and 2009 was $14.8 million and $10.6 million, respectively, which is included in other investments on our balance sheet. The increase in our equity investment balance over the last 12 months is due to $2.7 million of equity contributions plus $1.5 million for our share of income allocation based on our 50 percent ownership interest. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50 percent owner.

PGH Impairment Analysis. In May 2010, we learned that the company proposing to build an LNG terminal on the Columbia River had suspended its operations and filed for bankruptcy. This company previously entered into a precedent agreement with Palomar for a majority of the transmission capacity on the proposed pipeline. As of June 30, 2010, Palomar had incurred a total $44.8 million of capital costs, including AFUDC (allowance for funds used during construction), toward the development of the pipeline (both east and west segments), and it had collected $15.8 million from a letter of credit which supported the bankrupt shipper's obligations under a prior precedent agreement. In addition, Palomar holds credit support in the form of a lien on assets of the bankrupt shipper under terms of the current precedent agreement.

Our equity investment balance in PGH as of June 30, 2010 was $14.8 million. We performed an impairment analysis of our total equity investment as of June 30, 2010 and determined that no impairment write-down is needed because the value of the expected development of this pipeline will exceed our total equity investment. If, however, we learn that the project is not viable, we could be required to recognize an impairment of up to approximately $14 million based on the amount of our equity investment as of June 30, 2010 net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as needed.

9. Comprehensive Income

Items excluded from net income and charged directly to stockholders' equity are included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in stockholders' equity is $5.8 million and $4.3 million as of June 30, 2010 and 2009, respectively, which is related to employee benefit plan liabilities. The following table provides a reconciliation of net income to total comprehensive income for the three and six months ended June 30, 2010 and 2009.

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	2010	2009	2010	2009
Net income	$6,888	$3,086	$50,496	$50,449
Amortization of employee benefit plan liability, net of tax	98	63	196	126

Total comprehensive income	$6,986	$3,149	$50,692	$50,575

14

Table of Contents

10. Derivative Instruments

We enter into swap, option and combinations of option contracts for the purpose of hedging natural gas and the forecasted issuance of fixed-rate debt which qualify as derivative instruments under accounting rules for derivative instruments and hedging activities. We primarily use these derivative financial instruments to manage commodity prices related to our natural gas purchase requirements and to manage interest rate risk exposure related to our long-term debt issuances.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to the physical gas supply contracts. Derivatives entered into prudently for future gas years prior to our annual Purchased Gas Adjustment (PGA) filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate was set on November 1, 2009 that are for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for 90 percent of the changes in fair value to be deferred as regulatory assets or liabilities and the remaining 10 percent to be recorded to the income statement for contracts not qualifying for cash flow hedge accounting and to other comprehensive income for contracts qualifying for cash flow hedge accounting.

Most of our commodity hedging for the upcoming gas year is completed prior to the start of each gas year, and these hedge prices are included in our annual PGA filing. We typically hedge approximately 75 percent of our anticipated year-round sales volumes based on normal weather. We entered the 2009-10 gas year (November 1, 2009 – October 31, 2010) hedged at a targeted level of 75 percent, including 60 percent financially hedged and 15 percent physically hedged through gas storage volumes. Our policy allows us to hedge price risk for up to 100 percent of our gas supplies for the next gas year and up to 50 percent for the following gas year.

At June 30, 2010 and 2009, we were hedged with financial contracts for the upcoming gas year at approximately 45 percent and 48 percent, respectively, based on anticipated sales volumes. At June 30, 2010, we were also hedged with financial contracts for the 2011-12 gas year between 10 and 15 percent.

The following table discloses the balance sheet presentation of our derivative instruments as of June 30, 2010 and 2009 and December 31, 2009:

	Fair Value of Derivative Instruments					
	June 30, 2010		June 30, 2009		December 31, 2009	
Thousands	Current	Non-Current	Current	Non-Current	Current	Non-Current
Assets:(1)						
Natural gas commodity	$ 1,495	$ 453	$ 5,293	$ 289	$ 6,214	$ 843
Foreign exchange	-	-	-	-	290	-
Total	$ 1,495	$ 453	$ 5,293	$ 289	$ 6,504	$ 843
Liabilities:(2)						
Natural gas commodity	$ 34,124	$ 16,917	$ 69,999	$ 8,844	$ 19,643	$ 3,193
Foreign exchange	339	-	53	-	-	-
Total	$ 34,463	$ 16,917	$ 70,052	$ 8,844	$ 19,643	$ 3,193

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

Table of Contents

The following table discloses the income statement presentation for the unrealized gains and losses from our derivative instruments for the three and six months ended June 30, 2010 and 2009. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting.

	Three Months Ended			
	June 30, 2010		June 30, 2009	
Thousands	Natural gas commodity(1)	Foreign exchange (2)	Natural gas commodity(1)	Foreign exchange (2)
Cost of sales	$ 8,471	$ -	$ 44,446	$ -
Other comprehensive income	-	(356)	-	101
Gain (loss) recognized in income (ineffective portion)	-	-	-	-
Less:				
Amounts deferred to regulatory accounts on balance sheet	(8,471)	356	(44,446)	(101)
Total impact on earnings	$ -	$ -	$ -	$ -

	Six Months Ended			
	June 30, 2010		June 30, 2009	
Thousands	Natural gas commodity(1)	Foreign exchange (2)	Natural gas commodity(1)	Foreign exchange (2)
Cost of sales	$ (49,093)	$ -	$ (73,261)	$ -
Other comprehensive income	-	(339)	-	(53)
Gain (loss) recognized in income (ineffective portion)	-	-	-	-
Less:				
Amounts deferred to regulatory accounts on balance sheet	49,093	339	73,261	53
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.

(2) 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.

Table of Contents

Our derivative liabilities exclude the netting of collateral. We had no collateral posted with our counterparties as of June 30, 2010 or 2009. We attempt to minimize the potential exposure to collateral calls by our counterparties to manage our liquidity risk. Based on our current credit ratings, most counterparties allow us credit limits ranging from $15 million to $25 million before collateral postings are required. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We also could be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current contracts outstanding, which reflect unrealized losses of $50.3 million at June 30, 2010, we have estimated the projected collateral demands, with and without potential adequate assurance calls, using current gas prices and various downgrade credit rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$-	$-	$4,198	$22,225
Without Adequate Assurance Calls	$ -	$-	$-	$4,198	$22,225

In the three and six months ended June 30, 2010, we realized net losses of $14.6 million and $20.8 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas, compared to net losses of $42.4 million and $121.7 million, respectively, for the three and six months ended June 30, 2009. 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 is being 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 from counterparties in order for them to meet our minimum credit requirement standards.

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; instead 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 earnings at-risk trading limits. Our credit risk for all outstanding derivatives at June 30, 2010 does not extend beyond October 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.

Table of Contents

Fair Value

In accordance with fair value accounting, 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 non-performance risk is generally derived from the credit default swap market and 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, 2010. We also did not have any transfers between level 1 or level 2 during the six months ended June 30, 2010 and 2009.

The following table provides the fair value hierarchy of our derivative assets and liabilities as of the six months ended June 30, 2010 and 2009 and December 31, 2009:

Thousands	Description of Derivative Inputs	June 30, 2010	June 30, 2009	December 31, 2009
Level 1	Quoted prices in active markets	$-	$-	$-
Level 2	Significant other observable inputs	(49,432)	(73,314)	(15,489)
Level 3	Significant unobservable inputs	-	-	-
		$(49,432)	$(73,314)	$(15,489)

11. Commitments and Contingencies

Environmental Matters

We own, or have previously owned, properties that may 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, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot currently be reasonably estimated. See Part II, Item 8., Note 11, in the 2009 Form 10-K.

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 (FFS) for groundwater source control, ODEQ conditionally approved the FFS in March 2008, subject to the submission of additional information. We have provided that information to ODEQ and are waiting for final approval from the agency. During the third quarter of 2009, we signed a joint Order on Consent with the Environmental Protection Agency (EPA) which requires the design of a final remedial action for the Gasco sediments. We have a liability accrued of $51.5 million at June 30, 2010 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). We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The liability accrued at June 30, 2010 for the Siltronic site is $1.1 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.

Table of Contents

Portland Harbor site. In 1998, the ODEQ and the EPA completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes an 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 Remedial Investigation/Feasibility Study (RI/FS), completion of which is scheduled for 2011. The EPA and the Lower Willamette Group are conducting focused studies on approximately nine miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. 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. As of June 30, 2010, we have a liability accrued of $8.4 million for this site, which is at the low end of the range of the 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 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 $9.9 million. To date, we have paid $9.6 million on work related to the removal of the tar deposit. As of June 30, 2010, we have a liability accrued of $0.3 million for our estimate of ongoing costs related to this tar deposit removal.

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 2008, 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, 2010, we have a liability accrued of $0.5 million 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. 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 source control investigation and a historical report were submitted to ODEQ and initial studies have been completed. ODEQ approval of the work plans has been received and studies are underway. As of June 30, 2010, we have an estimated liability accrued of $0.2 million for the study of the site, which will include investigation of sediments and the preparation of a 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.

Table of Contents

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at June 30, 2010 and 2009 and December 31, 2009:

	Current Liabilities			Non-Current Liabilities		
Thousands	June 30, 2010	June 30, 2009	Dec. 31, 2009	June 30, 2010	June 30, 2009	Dec. 31, 2009
Gasco site	$7,996	$11,373	$9,841	$43,522	$7,615	$43,659
Siltronic site	724	722	653	358	179	593
Portland Harbor site	1,836	-	2,114	6,875	13,401	7,272
Central Service Center site	5	-	5	510	523	511
Front Street site	72	221	72	166	-	436
Other sites	-	-	-	117	90	123
Total	$10,633	$12,316	$12,685	$51,548	$21,808	$52,594

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the Oregon Public Utility Commission (OPUC) approved our request to defer unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC granted us additional authorization 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, the authorized cost deferral and interest accrual has been extended through January 2011.

On a cumulative basis, we have recognized a total of $102.6 million for environmental costs, including legal, investigation, monitoring and remediation costs, including $4.9 million accrued and paid prior to regulatory deferral order approval. At June 30, 2010, we had a regulatory asset of $109.3 million, which includes $41 million of total paid expenditures to date, $56.7 million for additional environmental costs expected to be paid in the future and accrued interest of $11.6 million. While we believe recovery of these deferred charges is probable through the regulatory process, we intend to pursue recovery from insurance carriers under our general liability insurance policies prior to seeking recovery through rates. Our 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. In the event that settlements cannot be reached, we intend to pursue other legal remedies. We continue to anticipate that our overall insurance recovery effort will extend over several years.

Table of Contents

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, 2010 and 2009 and December 31, 2009:

	Non-Current Regulatory Assets		
Thousands	June 30, 2010	June 30, 2009	December 31, 2009
Gasco site	$71,531	$32,688	$69,607
Siltronic site	3,068	2,367	2,974
Portland Harbor site	32,712	33,727	31,500
Central Service Center site	551	548	550
Front Street site	1,056	350	910
Other sites	406	371	507
Total	$109,324	$70,051	$106,048

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. Although the final outcome of this proceeding cannot be predicted with certainty, 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.

Table of Contents

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, 2010 and 2009. 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 2009 Annual Report on Form 10-K (2009 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), NW Natural Gas Storage, LLC, which is a subsidiary of our wholly-owned subsidiary NW Natural Energy, LLC, and an equity investment in Palomar Gas Holdings, LLC (PGH) to develop a proposed natural gas pipeline through its wholly-owned subsidiary Palomar Gas Transmission LLC (Palomar). These accounts include our regulated local gas distribution business, our gas storage business, 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) as well as 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 2009 Form 10-K). We also believe that showing operating revenues and margins excluding the refund of gas cost savings on customer bills in June 2009 facilitates more meaningful comparisons between 2009 and 2010. We use such non-GAAP (i.e. non generally accepted accounting principle) financial measures in analyzing our results of operations and believe that they provide useful information to our investors and creditors in evaluating our financial condition.

Certain prior year balances on our consolidated financial statements have been reclassified to conform with the current presentation. These reclassifications had no impact on our prior year's consolidated results of operations, and no material impact on financial condition or cash flows.

Executive Summary

Results for the second quarter of 2010 include:

- Consolidated net income increased $3.8 million, from $3.1 million in the second quarter of 2009 to $6.9 million in the second quarter of 2010;
- Earnings from utility operations increased $4.2 million, from net income of $0.4 million in 2009 to net income of $4.6 million in 2010;
    - Earnings from gas storage operations decreased $0.6 million, from net income of $2.7 million in 2009 to $2.1 million in 2010;
- Net operating revenues (margin) increased 10 percent, from $65.9 million in 2009 to $72.2 million in 2010, with utility margin up 11 percent or $6.9 million and gas storage margin down 11 percent or $0.6 million;
- Cash flow from operations decreased 48 percent, from $199.8 million in 2009 to $104.3 million in 2010; and
    - Utility customer growth rate was slightly above 1 percent over the last 12 months.

Table of Contents

Issues, Challenges and Performance Measures

Economic weakness. Ongoing weakness in local and U.S. economies has continued to impact consumer growth and business demand for natural gas. Although these conditions may continue to have a negative impact on our financial results, we are beginning to see some signs the economy may be stabilizing. Most recently, our annual customer growth rate was 1 percent at June 30, 2010 compared to 0.7 percent at March 31, 2010 and 0.8 percent at June 30, 2009. We have also seen some rebound in our industrial market as volumes and margins increased year over year for the second quarter in a row, and our bad debt expense decreased $2.5 million compared to last year on significantly lower delinquent balances. Despite these improvements, we are still faced with 10 to 11 percent unemployment rates and a sluggish business environment. Regardless of these challenges, we believe we are well positioned to continue adding customers due to our relatively low market penetration, our efforts to convert homes to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

Managing gas prices and supplies. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. With recent success in new drilling technologies and substantial new supplies from shale gas, the supply of North American natural gas has increased dramatically, which has contributed to lower gas prices. We entered the 2009-10 gas year, which began November 1, 2009, hedged at a targeted level of approximately 75 percent of our estimated gas purchase volumes for the gas contract year. In addition, we are currently hedged on gas prices for 45 percent of our forecasted purchase volumes for the next gas year and for between 10 and 15 percent for the following year. Our policy allows us to hedge up to 100 percent of our gas supply requirements for the next gas year and up to 50 percent for the following year. Our Purchased Gas Adjustment (PGA) mechanism, along with gas price hedging strategies and gas supplies in storage, enable us to reduce earnings risk exposure and secure lower gas costs for customers. These lower gas prices, coupled with good customer service and energy efficiency programs for our customers, can help the strengthen natural gas competitive advantage compared to other fuels. In addition to hedging gas prices over the next three years, we are evaluating and developing other gas acquisition strategies to potentially manage gas price volatility for customers beyond three years.

Environmental investigation and remediation costs. We accrue all material environmental loss contingencies related to our properties that require environmental investigation or remediation. Due to numerous uncertainties surrounding the preliminary nature of investigations or the developing nature of remediation requirements, actual costs could vary significantly from our loss estimates. As a regulated utility, we are required to defer certain costs pursuant to regulatory decisions including environmental costs, and to seek recovery of these amounts in future rates to customers. However, before we seek recovery from customers, we intend to pursue recovery from insurance policies. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage costs and demonstrate that costs were prudently incurred. Recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. See Note 11 in this report and Note 11 in our 2009 Form 10-K.

Climate change. We recognize that our businesses will be impacted by future carbon constraints. The outcome of federal, state, local and international climate change initiatives cannot be determined at this time, but these initiatives could produce a number of results including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. While our CO2 equivalent emission levels are relatively small, the adoption and implementation of any regulations imposing reporting obligations, or limiting emissions of greenhouse gases associated with our operations, could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas has a relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for electric production, direct use in homes and businesses and as a reliable and relatively low-emission back-up fuel source for alternative energy sources.

23

Table of Contents

Strategies and Performance Measures. In order to deal with the challenges affecting our businesses, we annually review and update our strategic plan to map our course over the next several years. Our plan includes strategies for: further improving our core gas distribution business; growing our non-utility gas storage business; investing in new natural gas infrastructure in the region; and maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support new clean energy technologies. We intend to measure our performance and monitor progress of certain metrics including, but not limited to: earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction ratings; utility margin; capital, operations and maintenance expense per customer; and non-utility earnings before interest, taxes, depreciation and amortization (non-utility 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 2009, we announced a voluntary severance program to reduce staffing levels in response to work load declines related to the current low customer growth environment and efficiency improvements. Severance programs and normal attrition resulted in reductions of full-time positions from 1,133 at December 31, 2008 to slightly over 1,000 at June 30, 2010, which are reflected in decreases in operation and maintenance costs and utility capital expenditures.

Technology investments, workforce reductions and other initiatives discussed above are expected to contribute to long-term operational efficiencies and reduce operating and capital costs throughout NW Natural.

Gas Storage Development. In 2007, we entered into a joint project agreement with Pacific Gas & Electric Company (PG&E) to develop, own and operate an underground natural gas storage facility near Fresno, California. Our undivided ownership interest in the project is held by our wholly-owned subsidiary, Gill Ranch. Gill Ranch is planning and developing the project and upon completion will operate the facility. Gill Ranch’s provision of market-based rate storage services in California will be subject to California Public Utility Commission (CPUC) regulation including, but not limited to, service terms and conditions, tariff compliance, securities issuances, lien grants and sales of property. Construction of this facility began in January 2010. Our share of the total project cost is currently estimated to be between $185 million and $205 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 gas storage facility is targeted to be in-service by the end of the third quarter of 2010, and we are currently hiring key staff for our non-utility gas storage business.

We also plan to continue expanding our interstate storage facilities at Mist, Oregon. In order to adequately complete the studies necessary for the next storage project at Mist, we have delayed the timeline for the next expansion but will continue to move forward with planning. We believe the earliest possible timeframe for moving forward with construction is 2011 or 2012, however we have not determined a targeted construction schedule or in-service date at this time. We are continuing to design the project scope and update our cost estimate for this next Mist expansion, which we expect will include the development of storage wells, a second compression station and a pipeline gathering system that will also enable future storage expansions.

Pipeline Diversification. Currently our utility and gas storage at Mist depend on a single bi-directional interstate pipeline to ship gas supplies. Palomar, a wholly-owned subsidiary of PGH, seeks to build a new gas transmission pipeline that would provide a new interconnection with our utility distribution system. PGH is owned 50 percent by us and 50 percent by Gas Transmission Northwest Corporation (GTN), an indirect wholly-owned subsidiary of TransCanada Corporation. The proposed Palomar pipeline is designed to serve our utility and the growing natural gas markets in Oregon and other parts of the Pacific Northwest. The proposed pipeline would be regulated by the Federal Energy Regulatory Commission (FERC).

Table of Contents

As originally proposed, the Palomar pipeline included an east and west segment. The east segment 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 two liquefied natural gas (LNG) terminals proposed to be built on the Columbia River. The east segment would not only 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 different regions in western Canada and the U.S. Rocky Mountains, but also provide other shippers potential access in the region. The west segment of the proposed pipeline was intended to provide the region, as well as our utility customers, with potential access to a new source of gas supply if an LNG terminal is built on the Columbia River.

In May 2010, we learned that the company proposing to build an LNG terminal on the Columbia River had suspended its operations and filed for bankruptcy. This company had previously entered into a precedent agreement for a majority of the proposed pipeline’s capacity. The bankruptcy court’s Trustees have not yet determined whether the precedent agreement will be assumed or rejected. Until the Trustees determine the status of the precedent agreement under the bankruptcy proceeding, Palomar will continue commercially reasonable efforts related to developing the proposed pipeline and it will monitor and evaluate the bankruptcy proceeding to determine its impact on the future development of the Palomar project.

As of June 30, 2010, Palomar had incurred a total of $44.8 million ($18.9 million for the west segment and $25.9 million for the east segment) of capital costs for the pipeline development, including AFUDC (allowance for funds used during construction), toward the development of the Palomar pipeline and it had collected $15.8 million from a letter of credit which supported the bankrupt shipper’s obligations under its prior precedent agreement. In addition, Palomar holds credit support in the form of a lien on assets of the bankrupt shipper under terms of the current precedent agreement.

As of June 30, 2010, our equity investment in PGH to develop the Palomar project was $14.8 million. Based on our review of the bankruptcy proceeding at this time, we believe the bankrupt shipper’s precedent agreement is likely to be rejected and the west segment of the proposed pipeline would not likely go forward without a replacement agreement of the type and magnitude of the current precedent agreement. However, we believe the proposed pipeline’s east segment is still a viable project, and the Palomar project remains in a development stage. We performed an impairment analysis for our total equity investment as of June 30, 2010 and determined that no impairment write-down is needed (see Note 8).

Palomar is continuing to work on permitting activities and on certain aspects of its regulatory application with the FERC, which will need to be amended to reflect the outcome from the bankruptcy. Palomar is having discussions with prospective regional shippers to evaluate the level of commercial support for the east segment and to determine the timing of its construction. We believe that the east segment is viable and Palomar will continue to focus on permitting activities during 2010, but the date for when the Palomar pipeline is expected to go into service will be impacted by the timing of our final FERC permit and the needs of shippers. See "Financial Condition—Cash Flows—Investing Activities," below for further discussion on the status of Palomar.

Consolidated Earnings and Dividends

Three months ended June 30, 2010 compared to June 30, 2009:

For the three months ended June 30, 2010, we had net income of $6.9 million, or 26 cents per share, compared to net income of $3.1 million, or 12 cents per share, for the same period last year.

Table of Contents

The primary factors contributing to increased second quarter net income were:

- a $7.3 million increase in utility margin, after adjustments for weather and decoupling mechanisms, from higher sales volumes to residential and commercial customers due to weather that was 49 percent colder than the same period in 2009, customer growth of 1 percent and recovery of higher income tax expense related to the amortization of regulatory tax assets (see “Results of Operations—Consolidated Operating Expenses—Income Tax Expense,” below);
- a $1.7 million increase in utility margin from a regulatory adjustment for income taxes paid versus collected in rates; and
- a $1.8 million decrease in operation and maintenance expense primarily due to lower payroll expense related to a reduced number of employees and lower bad debt expense.

Partially offsetting the above factors were:

- a $2.1 million decrease in utility margin from our regulatory share of gas cost savings, from $2.6 million in 2009 to $0.5 million in 2010;
- a $1.0 million increase in general taxes reflecting a net increase in property taxes related to property, plant, and equipment additions; and
- a $0.6 million decrease in margin from gas storage operations primarily from startup costs at Gill Ranch.

Six months ended June 30, 2010 compared to June 30, 2009:

Net income was $50.5 million, or $1.90 per share, for the six months ended June 30, 2010, compared to $50.4 million, or $1.90 per share, for the same period last year.

The primary factors contributing to the $0.1 million increase in net income were:

- a $6.1 million net increase in pre-tax income related to a refund of property taxes, reflecting a $5.2 million decrease to general taxes and a $1.9 million increase to interest income, partially offset by a $1.0 million increase to operation and maintenance expense for property tax consultant and legal fees;
- an additional $6.1 million decrease in operation and maintenance expense primarily due to a decrease in bad debts, lower payroll and pension expense; and
- a $4.5 million increase in utility margin, after adjustments for weather and decoupling adjustments, primarily from colder weather in the second quarter of 2010 and recovery of higher income tax expense related to the amortization of regulatory tax assets (see “Results of Operations—Consolidated Operating Expenses—Income Tax Expense,” below).

Partially offsetting the above factors were:

- a $10.4 million decrease in utility margin due to lower gas cost savings from our regulatory incentive sharing mechanism, from $11.1 million in 2009 to $0.7 million in 2010; and
- a $1.7 million increase in interest charges reflecting higher balances of long-term debt outstanding.

Dividends paid on our common stock were 41.5 cents per share in the second quarter of 2010, compared to 39.5 cents per share in the second quarter of 2009. In July 2010, the Board of Directors declared a quarterly dividend on our common stock of 41.5 cents per share, payable on August 13, 2010 to shareholders of record on July 30, 2010. The current indicated annual dividend rate is $1.66 per share.

Table of Contents

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 and postretirement benefits;
- income taxes; and
- environmental contingencies.

There have been no material changes to the information provided in the 2009 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 2009 Form 10-K). Management has discussed its current 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.

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), FERC and with respect to Gill Ranch, the CPUC. The OPUC and WUTC, and with respect to Gill Ranch, the CPUC, also regulate our issuance of securities. In 2009, approximately 90 percent of our utility gas volumes were 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 Oregon and southwest Washington in particular, and 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 2009 Form 10-K.

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, gas purchases 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.

Table of Contents

The OPUC and WUTC approved rate changes effective on November 1, 2009 under our PGA mechanisms. The effect of these rate changes was to decrease the average monthly bills of Oregon residential customers by 18 percent, partially offset by an increase of 2 percent in the public purpose charge, which resulted in a net decrease of 16 percent. The average monthly bills of Washington residential customers decreased by 22 percent.

Under the current Oregon PGA incentive sharing mechanism, we are required to select by August 1 of each year, either an 80 percent deferral or 90 percent deferral of higher or lower actual gas costs compared to PGA prices such that the impact on current earnings from the gas cost incentive sharing is either 20 percent or 10 percent, respectively. In addition to the gas cost incentive sharing mechanism, we are also subject to an annual earnings review to determine if the utility is earning above its allowed return on equity (ROE) threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level will be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for the 2009-2010 and 2010-2011 PGA years. The ROE threshold is subject to adjustment up or down annually based on movements in long-term interest rates. For the 2008 calendar year, the ROE threshold after adjustment for long-term interest rates was 13.1 percent, and no amounts were required to be refunded to customers. For the 2009 calendar year, the ROE threshold after adjustment for long-term interest rates was 11.5 percent. We expect the 2009 earnings review by the OPUC to be completed during the third quarter of 2010, and based on our preliminary estimate we do not expect a refund to utility customers for earnings above the ROE threshold for 2009.

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. We do not have an earnings sharing mechanism in Washington.

Regulatory Recovery for Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue interest paid on 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. These authorizations have been extended through January 2011. See Note 11.

Pension Deferral. We are currently subject to a regulatory deferral order from the OPUC whereby we refund cost savings to customers when our annual pension expense is below the amount set in rates during our last general rate case. However, we are currently not authorized to defer and recover any cost increases from customers when our annual pension expense is above the amount set in rates. For 2010, our pension expense is expected to be between $3 million and $4 million above the amount set in rates. In March 2010, we filed a request with the OPUC for authorization to defer pension expenses above the amount set in rates, and to recover the amount through future rate increases or through a balancing account mechanism that would include the effects of anticipated lower pension expenses in future years. We expect a decision from the OPUC by the end of this year.

Customer Refunds for Gas Storage Sharing. In June 2010, $11 million was refunded to utility customers from our regulatory incentive sharing mechanism related to gas storage services at Mist and optimization services (see “Business Segments Other Utility—Gas Storage,” below). In June 2009, we refunded $7.2 million to customers for the same regulatory mechanism.

Table of Contents

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 tariff mechanism that adjusts revenues to offset changes in margin resulting from increases or decreases in average 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 2009 Form 10-K). Both mechanisms are designed to reduce the volatility of our utility earnings.

Three months ended June 30, 2010 compared to June 30, 2009:

Utility operations resulted in net income of $4.6 million, or 17 cents per share, in the second quarter of 2010 compared to net income of $0.4 million, or 2 cents per share, in the second quarter of 2009. The $4.2 million increase over 2009 is primarily due to weather that was 49 percent colder than 2009 (for further information see "Residential and Commercial Sales," below). The increase in utility margin from colder weather during the second quarter of 2010 was partially offset by a reduction in our regulatory share of gas cost savings in 2010 compared to 2009 (see "Cost of Gas Sold," below). Total utility volumes sold and delivered in the second quarter of this year increased by 12 percent over last year.

Six months ended June 30, 2010 compared to June 30, 2009:

In the six months ended June 30, 2010, utility operations contributed net income of $45.5 million or $1.71 per share, compared to $45.7 million or $1.72 per share in 2009. Total utility volumes sold and delivered in the six months ended June 30, 2010 decreased by 9 percent over last year primarily due to 4 percent warmer weather, while total utility margin decreased by $5.7 million, or 3 percent, primarily due to a $10.4 million decrease in gas cost savings from our incentive sharing mechanism, partially offset by a $4.5 million increase in residential and commercial margins, after weather and decoupling mechanism adjustments, primarily related to the benefits of colder weather in the second quarter of 2010 (see "Residential and Commercial Sales," below).

Table of Contents

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

Thousands, except degree day data	Three Months Ended June 30, 2010	2009	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	72,094	58,156	13,938
Commercial sales	47,837	43,497	4,340
Industrial - firm sales	8,625	8,568	57
Industrial - firm transportation	31,156	29,377	1,779
Industrial - interruptible sales	13,924	17,368	(3,444)
Industrial - interruptible transportation	59,751	52,229	7,522
Total utility volumes sold and delivered	233,387	209,195	24,192
Utility operating revenues - dollars:			
Residential sales	$84,002	$72,491	$ 11,511
Commercial sales	44,126	42,311	1,815
Industrial - firm sales	6,782	7,949	(1,167)
Industrial - firm transportation	1,382	1,442	(60)
Industrial - interruptible sales	8,196	13,280	(5,084)
Industrial - interruptible transportation	1,981	2,039	(58)
Regulatory adjustment for income taxes paid(1)	1,034	(626)	1,660
Other revenues	9,599	4,290	5,309
Total utility operating revenues	157,102	143,176	13,926
Cost of gas sold	86,292	79,359	(6,933)
Revenue taxes	3,871	3,753	(118)
Utility margin	$66,939	$60,064	$ 6,875
Utility margin:(2)			
Residential sales	$41,098	$34,901	$ 6,197
Commercial sales	16,552	14,793	1,759
Industrial - sales and transportation	7,119	6,524	595
Miscellaneous revenues	1,303	1,474	(171)
Gain (loss) from gas cost incentive sharing	496	2,647	(2,151)
Other margin adjustments	105	496	(391)
Margin before regulatory adjustments	66,673	60,835	5,838
Weather normalization adjustment	(1,901)	(756)	(1,145)
Decoupling adjustment	1,133	611	522
Regulatory adjustment for income taxes paid(1)	1,034	(626)	1,660
Utility margin	$66,939	$60,064	$ 6,875
Customers - end of period:			
Residential customers	606,323	599,614	6,709
Commercial customers	62,171	61,938	233
Industrial customers	911	923	(12)
Total number of customers - end of period	669,405	662,475	6,930
Actual degree days	857	577	
Percent colder (warmer) than average weather(3)	25%	(16)%	

Table of Contents

Thousands, except degree day data	Six Months Ended June 30, 2010	2009	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	205,954	236,545	(30,591)
Commercial sales	126,693	146,614	(19,921)
Industrial - firm sales	18,778	20,605	(1,827)
Industrial - firm transportation	63,767	64,778	(1,011)
Industrial - interruptible sales	30,248	40,267	(10,019)
Industrial - interruptible transportation	121,350	111,696	9,654
Total utility volumes sold and delivered	566,790	620,505	(53,715)
Utility operating revenues - dollars:			
Residential sales	$ 253,611	$ 325,548	$ (71,937)
Commercial sales	124,201	171,661	(47,460)
Industrial - firm sales	15,400	21,653	(6,253)
Industrial - firm transportation	2,818	2,844	(26)
Industrial - interruptible sales	18,577	35,219	(16,642)
Industrial - interruptible transportation	3,900	3,961	(61)
Regulatory adjustment for income taxes paid(1)	4,018	2,887	1,131
Other revenues	15,640	12,203	3,437
Total utility operating revenues	438,165	575,976	(137,811)
Cost of gas sold	234,840	363,523	128,683
Revenue taxes	10,913	14,295	3,382
Utility margin	$ 192,412	$ 198,158	$ (5,746)
Utility margin:(2)			
Residential sales	$ 107,502	$ 121,234	$ (13,732)
Commercial sales	42,260	48,567	(6,307)
Industrial - sales and transportation	14,242	13,946	296
Miscellaneous revenues	2,976	3,366	(390)
Gain (loss) from gas cost incentive sharing	695	11,079	(10,384)
Other margin adjustments	86	994	(908)
Margin before regulatory adjustments	167,761	199,186	(31,425)
Weather normalization adjustment	11,634	(9,470)	21,104
Decoupling adjustment	8,999	5,555	3,444
Regulatory adjustment for income taxes paid(1)	4,018	2,887	1,131
Utility margin	$ 192,412	$ 198,158	$ (5,746)
Actual degree days	2,484	2,598	
Percent colder (warmer) than average weather(3)	(3)%	2%	

(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.

31

Table of Contents

In June 2009, we refunded $35.3 million to our Oregon and Washington customers for accumulated gas cost savings in our regulatory deferred account. Because this refund was such a significant amount, which materially affected utility operating revenues for the three and six months ended June 30, 2009, we have provided the following non-GAAP table summarizing the impact of this refund on our utility operating revenues and margin for the three and six months ended June 30, 2009, and a comparison to 2010:

		Three Months Ended		
		June 30, 2009		
Thousands	June 30, 2010	As Reported	Refund	Excluding Refund (Non-GAAP)
Utility operating revenues:				
Residential sales	$84,002	$72,491	$19,679	$ 92,170
Commercial sales	44,126	42,311	11,423	53,734
Industrial - firm sales	6,782	7,949	1,515	9,464
Industrial - firm transportation	1,382	1,442	-	1,442
Industrial - interruptible sales	8,196	13,280	2,673	15,953
Industrial - interruptible transportation	1,981	2,039	-	2,039
Regulatory adjustment for income taxes paid	1,034	(626)	-	(626)
Other revenue	9,599	4,290	-	4,290
Total utility operating revenues	157,102	143,176	35,290	178,466
Cost of gas sold	86,292	79,359	34,206	113,565
Revenue taxes	3,871	3,753	887	4,640
Utility margin	$66,939	$60,064	$197	$ 60,261

		Six Months Ended		
		June 30, 2009		
Thousands	June 30, 2010	As Reported	Refund	Excluding Refund (Non-GAAP)
Utility operating revenues:				
Residential sales	$253,611	$325,548	$19,679	$ 345,227
Commercial sales	124,201	171,661	11,423	183,084
Industrial - firm sales	15,400	21,653	1,515	23,168
Industrial - firm transportation	2,818	2,844	-	2,844
Industrial - interruptible sales	18,577	35,219	2,673	37,892
Industrial - interruptible transportation	3,900	3,961	-	3,961
Regulatory adjustment for income taxes paid	4,018	2,887	-	2,887
Other revenue	15,640	12,203	-	12,203
Total utility operating revenues	438,165	575,976	35,290	611,266
Cost of gas sold	234,840	363,523	34,206	397,729
Revenue taxes	10,913	14,295	887	15,182
Utility margin	$192,412	$198,158	$197	$ 198,355

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 net reduction to margin of only $0.2 million. This decrease in utility margin was offset by lower revenue-based expenses including bad debt expense and lower regulatory fees.

Table of Contents

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 in our service area. 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 will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced due to our weather normalization mechanism in Oregon, where about 90 percent of our customers are served. This mechanism is in effect for the period from December 1 through May 15 of each heating season, but customers are allowed to opt out of the mechanism. For the current gas year approximately 9 percent of our Oregon residential and commercial customers have opted out of the mechanism, which is fairly consistent with prior years. 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 and undermine Oregon's conservation policy and efforts. In Washington, where the remaining 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 fully insulated from earnings volatility due to weather and conservation in Washington.

Three months ended June 30, 2010 compared to June 30, 2009:

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 increased 18 percent due to weather that was 49 percent colder than the same period in 2009;
- utility operating revenues increased $13.3 million or 12 percent due to the $31.1 million in customer refunds in 2009 related to gas cost savings and related to increased volumes from colder weather, partially offset by lower rates in this year's PGA; and
- utility margin increased $7.3 million or 15 percent, including weather normalization and decoupling mechanism adjustments, primarily due to colder weather, customer growth of 1 percent, and an out of period adjustment of $1.0 million related to the fourth quarter of 2009 and the first quarter of 2010 which was not material to any prior or current periods.

Colder weather in this year's second quarter had a larger effect than normal. Because our weather mechanism is in effect for only half of the month of May, and the decoupling mechanism is adjusted for normal weather, we experience larger than normal changes in margin during May when the weather is colder or warmer than normal. For the month of May 2010, temperatures were 33 percent colder than normal. This triggered a higher use of gas by residential and commercial customers that was only partially offset by the weather normalization mechanism. As a result, the colder weather in May contributed about $2.8 million to margin.

Six months ended June 30, 2010 compared to June 30, 2009:

The primary factors contributing to changes in residential and commercial volumes and operating revenues in the six months ended June 30, 2010, compared to the same period last year were:

- sales volumes decreased 13 percent due to weather during that was 4 percent warmer than last year and customer conservation;
- utility operating revenues decreased $119.4 million or 24 percent primarily due to PGA rate decreases of 16 and 22 percent in Oregon and Washington, respectively, and 13 percent lower sales volumes, partially offset by $31.1 million in customer refunds in 2009 related to gas cost savings; and
-

utility margin increased $4.5 million or 3 percent, including weather normalization and decoupling adjustments, primarily due to benefits from colder weather during the second quarter of 2010 and customer growth of 1 percent over the last 12 months.

Table of Contents

Utility operating revenues include accruals for unbilled revenues 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, 2010, accrued unbilled revenue was $16.4 million, compared to $18.1 million at June 30, 2009, with the 9 percent decrease primarily due to lower billing rates.

Industrial Sales and Transportation

Industrial operating revenues include the commodity cost component of gas sold under sales service but not under transportation service. Therefore, industrial customer switching between sales service and transportation service can cause swings in utility operating revenues but generally our margins are unaffected because we do not mark up the cost of gas.

Three months ended June 30, 2010 compared to June 30, 2009:

The primary factors that impacted second quarter results from industrial sales and transportation markets were as follows:

- volumes delivered to industrial customers increased by 5.9 million therms, or 5 percent; and
- margin increased $0.6 million, or 9 percent, as a result of higher volumes and increases in higher margin rate schedules.

Six months ended June 30, 2010 compared to June 30, 2009:

The primary factors that impacted year-to-date results from industrial sales and transportation markets were as follows:

- volumes delivered to industrial customers decreased by 3.2 million therms, or 1 percent;
- margin increased $0.3 million, or 2 percent, as a result of fixed charges not affected by declining use and increases in higher margin rate schedules.

Regulatory Adjustment for Income Taxes Paid

Oregon law requires certain regulated natural gas and electric utilities, including NW Natural, to annually review the amount of income taxes collected in rates from utility operations and compare it to the amount the company actually pays to taxing authorities. Under this law, if we pay less in income taxes than we collect from our Oregon utility customers, or if our consolidated taxes paid are less than the taxes we collect from our Oregon utility customers, then we are required to refund the excess to our Oregon utility customers. Conversely, if we pay more income taxes than we actually collect from our Oregon utility customers, as calculated using rate increments from our most recent general rate case, then we are required to collect a surcharge from our Oregon utility customers.

For the six months ended June 30, 2010, we recognized $4 million of pre-tax income representing a difference of $3.8 million of estimated federal and state income taxes paid in excess of taxes collected in rates plus accrued interest of $0.2 million. For the six months ended June 30, 2009, we recognized a surcharge of $2.9 million, which included accrued interest of $0.2 million. The $1.1 million increase in income taxes paid over income taxes collected in rates is due in part to higher income from utility operations and higher effective income tax rates (see Note 7), partially offset by higher income taxes collected in rates.

Table of Contents

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. Although the decoupling adjustment and other regulatory deferral collections or refunds and amortizations 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 or decreases in customer sales rates.

Three months ended June 30, 2010 compared to June 30, 2009:

Other revenues were $9.6 million in the second quarter of 2010, an increase of $5.3 million over the second quarter of 2009, with the increase primarily due to a timing difference in how we collect our surcharge for regulatory adjustment for income taxes paid. In 2009 we collected the surcharge in a one-time billing adjustment. In 2010, we are collecting the surcharge in rates as an adjustment in our PGA. The timing of when we collect the surcharge has no impact on margin or net income.

Six months ended June 30, 2010 compared to June 30, 2009:

Other revenues were $15.6 million in the six months ended June 30, 2010, an increase of $3.4 million over the same period of 2009, with the increase primarily due to a timing difference in how we collect our surcharge for regulatory adjustment for income taxes paid. In 2009 we collected the surcharge in a one-time billing adjustment. In 2010, we are collecting the surcharge in rates as an adjustment in our PGA. The timing of when we collect the surcharge has no impact on margin or net income.

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. Our regulated utility does not generally earn a profit or incur a loss on gas commodity purchases. The OPUC and the WUTC require natural gas commodity costs 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 partially affected by differences between actual and expected purchased gas costs due to market fluctuations and volatility affecting unhedged purchases. To manage this earnings exposure, we use natural gas derivatives, primarily fixed-price commodity swaps, consistent with our financial derivatives policies. Gains and losses from financial hedge contracts are generally included 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, prices on unhedged purchases and hedged purchases entered into after the annual PGA filing in Oregon, if any, may impact net income to the extent of our share of any gain or loss under the PGA. 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 th 2009 Form 10-K, and Note 10 in this report).

Three months ended June 30, 2010 compared to June 30, 2009:

- total cost of gas sold increased $6.9 million, or 9 percent, due to a 12 percent increase in sales volumes, partially offset by lower gas prices;
    - the average gas cost collected through rates, excluding customer refunds for accumulated gas cost savings from prior quarters, decreased 31 percent from 89 cents per therm in 2009 to 61 cents per therm in 2010,

primarily reflecting the lower prices that were passed on to customers through the PGA effective November 1, 2009; and

- hedge losses totaling $14.6 million were realized and included in cost of gas sold this quarter, compared to $42.4 million of hedge losses in the same period of 2009.

Table of Contents

The effect on operating results from our gas cost incentive sharing mechanism was a margin gain of $0.5 million in the second quarter of 2010, compared to a margin gain of $2.6 million for the second quarter of 2009.

Six months ended June 30, 2010 compared to June 30, 2009:

- total cost of gas sold decreased $128.7 million, or 35 percent, due to a 9 percent decrease in total sales volumes and lower prices;
- the average gas cost collected through rates, excluding customer refunds, decreased 31 percent from 90 cents per therm in 2009 to 62 cents per therm in 2010, primarily reflecting lower prices that were passed on to customers through the PGA effective November 1, 2009; and
- hedge losses totaling $20.8 million were realized and included in cost of gas sold for the six months ended June 30, 2010, compared to $121.7 million of hedge losses in the same period of 2009.

The effect on operating results from our gas cost incentive sharing mechanism was a margin gain of $0.7 million in the six months ended June 30, 2010, compared to a margin gain of $11.1 million in the same period of 2009.

Business Segments Other than Utility Operations

Gas Storage

Our gas storage segment currently consists of the non-utility portion of our Mist underground storage facility, utility and non-utility asset optimization and start-up costs at Gill Ranch (see Part I, Item 1., "Business Segments—Gas Storage," in our 2009 Form 10-K). For the three months ended June 30, 2010, we earned $2.1 million, or 8 cents per share, compared to $2.7 million, or 10 cents per share, for the same period in 2009. The $0.6 million decrease in net income over 2009 is primarily due to lower revenues from optimization of utility gas storage and pipeline capacity and start-up costs at Gill Ranch. For the six months ended June 30, 2010, we earned $4.6 million, or 18 cents per share, compared to $4.8 million, or 18 cents per share, for the same period in 2009.

We provide gas storage services to customers in the interstate and intrastate markets from our Mist gas storage field in Oregon, primarily using storage capacity that has been developed in advance of core utility customers' requirements. Under a regulatory incentive sharing mechanism in Oregon, we retain 80 percent of pre-tax income from our Mist gas storage services and from optimization services when the costs of the capacity being used is not included in utility rates, and 33 percent of pre-tax income from such storage and optimization services when the capacity being used is pipeline or 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 began construction at Gill Ranch in January 2010. Our share of the project represents 75 percent of the total cost of the initial development, which includes an estimated 20 Bcf of gas storage capacity and about 27 miles of gas transmission pipeline. Our share of the total project cost is currently estimated between $185 and $205 million. Construction of the facility is progressing and on target with an in-service date by the end of the third quarter of 2010. As of June 30, 2010 and 2009, our construction investment balance in Gill Ranch was $162.8 million and $16.3 million, respectively. See Note 2 in the 2009 Form 10-K.

Other

Our other business segment consists of Financial Corporation, an investment in PGH, and other non-utility investments and business activities. Financial Corporation had total assets of $1.2 million and $1.3 million as of June 30, 2010 and 2009, respectively, reflecting a non-controlling interest in the Kelso-Beaver pipeline. Our net equity investment in PGH as of June 30, 2010 and 2009 was $14.8 million and $10.6 million, respectively. Net income from our other business segment for the three and six months ended June 30, 2010 was $0.1 million and $0.3 million, respectively, compared to a net loss of $0.1 million for both the three and six months ended June 30, 2009. See Note 2.

Table of Contents

Consolidated Operating Expenses

Operations and Maintenance

Three months ended June 30, 2010 compared to June 30, 2009:

Operations and maintenance expense was $28.4 million in 2010, compared to $30.2 million in 2009, a decrease of $1.8 million or 6 percent. The primary factors contributing to the decrease were:

- a $1.2 million decrease in utility bad debt expense (see further discussion below);
- a $1.0 million decrease in payroll expense related to a reduced number of employees; and
- a $0.7 million decrease in pension expense, a result of higher pension cost in 2009 due to the decline in the market value of plan investments in 2008.

Partially offsetting the above factors was:

- a $1.5 million increase in incentive bonus accruals due to improved operational results in the second quarter of 2010.

Six months ended June 30, 2010 compared to June 30, 2009:

Operations and maintenance expense was $59.1 million in 2010, compared to $64.1 million in 2009, a decrease of $5 million or 8 percent. The primary factors that contributed to the decrease in operations and maintenance expense were:

- a $2.5 million decrease in utility bad debt expense (see below for further discussion);
- a $1.8 million decrease in payroll expense related to a reduced number of employees; and
- a $1.1 million decrease in pension expense, a result of higher pension cost in 2009 due to the decline in the market value of plan investments in 2008.

Partially offsetting the above factors were:

- a $1.0 million increase for consulting and legal fees related to a successful property tax appeal; and
- a $0.6 million increase in incentive bonus accruals due to improved results in certain operating areas.

Our bad debt expense as a percent of revenues was 0.16 percent for the 12 months ended June 30, 2010, compared to 0.41 percent in the same period last year. Excluding customer refunds in June and July 2009 (see "Business Segments—Utility Operations," above), our bad debt expense as a percent of revenues was 0.36 percent for the 12 months ended June 30, 2009. Credit risks are still somewhat high due to the weak economy and high unemployment rates, but our credit environment has improved as evidenced by our 42 percent decrease in delinquent account balances over last year. Lower customer usage from warmer than normal weather this past winter coupled with customer conservation, lower gas prices and low income energy assistance funds have contributed to our reduced credit exposure.

General Taxes

Three months ended June 30, 2010 compared to June 30, 2009:

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, increased $1 million, or 15 percent, in the three months ended June 30, 2010 over the same period in 2009, primarily due to an increase in property taxes from net additions to property, plant and equipment.

Table of Contents

Six months ended June 30, 2010 compared to June 30, 2009:

For the six months ended June 30, 2010, general taxes decreased $4.3 million, or 28 percent, compared to the same period in 2009, due to a property tax refund of $5.2 million (see below), partially offset by an increase in property taxes from net additions to property, plant, and equipment.

We were involved in litigation with the Oregon Department of Revenue over whether inventories held for sale were required to be taxed as personal property. In January 2010, the Oregon Supreme Court unanimously ruled in our favor, stating that these inventories were exempt from property tax. As a result of this ruling, we were entitled to a refund of approximately $5.2 million, plus accrued interest, for property taxes paid on inventories beginning with the 2002-03 tax year. We recognized a net $6.1 million increase in pre-tax income in the first quarter of 2010, which consisted of $5.2 million for the refund of property taxes paid, $1.9 million for accrued interest income, and $1.0 million of increased operations and maintenance expense for legal and consulting services. As of June 30, 2010, we had received all of the property tax refunds.

Depreciation and Amortization

Depreciation and amortization expense increased by $0.7 million, or 4 percent for the three months ended June 30, 2010, compared to the same period in 2009. For the six months ended June 30, 2010, depreciation and amortization expense increased by $1 million, or 3 percent, compared to the same period in 2009. The increase in both periods reflects added utility plant from customer growth and other capital project expenditures.

Other Income and Expense – Net

The following table summarizes other income and expense – net by primary components for the three and six months ended June 30, 2010 and 2009:

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	2010	2009	2010	2009
Other income and expense - net:				
Gains from company-owned life insurance	$645	$921	$1,041	$2,002
Interest income	88	39	1,998	99
Income from equity investments	412	446	728	734
Net interest on deferred regulatory accounts	1,206	288	2,197	789
Other	(738)	(962)	(1,328)	(2,002)
Total other income and expense - net	$1,613	$732	$4,636	$1,622

Three months ended June 30, 2010 compared to June 30, 2009:

Other income and expense – net increased $0.9 million, primarily due to additional income from our higher deferred regulatory account balances.

Six months ended June 30, 2010 compared to June 30, 2009:

Other income and expense – net increased $3 million, primarily due to additional interest income from our deferred regulatory accounts and from $1.9 million in interest income related to the property tax refund discussed under "General Taxes," above.

Table of Contents

Interest Expense – Net

Interest expense – net increased $0.6 million and $1.7 million, or 6 percent and 9 percent, in the three and six months ended June 30, 2010 compared to the same periods in 2009, respectively. The increase is primarily due to higher balances on long-term debt outstanding, including the $75 million of 5.37 percent medium-term notes (MTNs) issued in March 2009 and the $50 million of 3.95 percent MTNs issued in July 2009 (see Note 5), partially offset by lower balances on short-term debt outstanding.

Income Tax Expense

Income tax expense increased $4.1 million in the six months ended June 30, 2010 compared to 2009. The effective tax rate was 40.5 percent in 2010 compared to 37.5 percent in 2009. The higher income tax expense and higher effective tax rate are the result of an increase in the Oregon corporate income tax rate, from 6.6 percent to 7.9 percent (see “Consolidated Operations—Income Tax Expense,” in the 2009 Form 10-K), and an increase in the amortization of our regulatory tax asset account on pre-1981 plant assets (see “Regulatory Matters—Rate Mechanisms—Depreciation Study,” in the 2009 Form 10-K).

On March 23, 2010, the Patient Protection and Affordable Care Act (the PPACA) was signed into law, and on March 30, 2010 the Health Care and Education Reconciliation Act of 2010 was signed into law. The PPACA changes the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide a benefit that is at least actuarially equivalent to the benefits under Medicare Part D. These subsidy payments become taxable in years beginning after December 31, 2012. Accounting guidance on income taxes requires the impact of this tax law change to be immediately recognized in the period that includes the enactment date. This tax provision of the PPACA did not have, and is not expected to have, an impact on our financial condition, results of operations or cash flows as we do not receive federal subsidy payments under Medicare Part D.

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,				December 31,	
	2010		2009		2009	
Common stock equity	48.2	%	49.2	%	47.2	%
Long-term debt	41.2	%	44.0	%	43.0	%
Short-term debt, including current maturities of long-term debt	10.6	%	6.8	%	9.8	%
Total	100	%	100	%	100	%

Table of Contents

Liquidity and Capital Resources

At June 30, 2010, we had $7.1 million of cash and cash equivalents compared to $31.1 million at June 30, 2009. We also had $0.9 million in restricted cash invested at Gill Ranch as of June 30, 2010, compared to $15.8 million as of June 30, 2009, which is being held as collateral for equipment purchase contracts and construction loans. In order to maintain sufficient liquidity during periods of volatile capital markets, at times we will maintain higher cash balances, add short-term borrowing capacity, and pre-fund utility capital expenditures while long-term fixed rate environments are attractive. Short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, committed multi-year credit facilities, cash available from 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 utility capital expenditures, refinance maturing short-term or long-term debt and provide for general corporate purposes. In March 2009, we issued $75 million of secured MTNs with an interest rate of 5.37 percent and a maturity date of February 1, 2020. In July 2009, we issued $50 million of secured MTNs with an interest rate of 3.95 percent and a maturity date of July 15, 2014.

The capital markets in the last two years, including the commercial paper market, experienced significant volatility and tight credit conditions, but conditions over the past 12 months improved as reflected by tighter credit spreads and increased access to new financing for investment grade issuers. With our current debt ratings (see “Credit Ratings,” below), we have been able to issue commercial paper and MTNs 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 new debt due to market conditions, we expect that our near term 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, subject to market conditions and regulatory approvals. We have OPUC approval to issue up to $175 million of additional MTNs under the existing shelf registration statement. We expect to file a new shelf registration statement, as required, prior to January 8, 2011.

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, 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 cash requirements and may trigger significant increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on June 30, 2010, we would be required to post approximately $22.2 million of collateral to our counterparties, but that would assume our long-term debt ratings were at non-investment grade levels, a level that is significantly lower than our current ratings (see Note 10 and “Credit Ratings,” below).

Based on several factors, including our current credit ratings, our recent experience issuing commercial paper, our current cash reserves, our committed credit facilities and other liquidity resources, and our expected 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 all contractual obligations and investing and financing activities discussed below.

In July 2010, The U.S. Congress passed and President Obama signed into law the “Wall Street Reform and Consumer Protection Act.” The new legislation will require additional government regulation of derivative and over-the-counter transactions, and that could expand collateral requirements. While we are currently evaluating the new legislation to determine its impact, if any, on our hedging procedures, results of operations, financial position and liquidity, we do not expect to know the full impact of the legislation until regulations implementing the legislation are finalized.

Off-Balance Sheet Arrangements

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

Table of Contents

Contractual Obligations

At June 30, 2010, our purchase commitments decreased $45.9 million since December 31, 2009, primarily due payments related to Gill Ranch (see “Financial Condition--Contractual Obligations,” in the 2009 Form 10-K).

Short-term Debt

Our primary source of short-term liquidity is from internal cash flows and the sale of commercial paper debt. 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 utility 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 over the last two years. At June 30, 2010 and 2009, our utility had commercial paper outstanding of $106.9 million and $79.8 million, respectively. In June 2010, Gill Ranch repaid its $40 million bank loan outstanding using the proceeds from its cash collateralized account.

Credit Agreement

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling $250 million, which may be extended for additional one-year periods subject to lender approval. All lenders under our credit agreement are major financial institutions with committed balances and investment grade credit ratings as of June 30, 2010 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 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 debt ratings, we believe the risk of lender default is minimal.

The loan commitments with all lenders under the syndicated credit agreement have been extended to May 31, 2013. The credit agreement 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 maturity date 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 maturity date. There were no outstanding balances under this credit agreement at June 30, 2010 and 2009. The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio as determined in accordance with the credit agreement 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, 2010 and 2009.

Table of Contents

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. 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).

Credit Ratings

Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets, including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. A change in our ratings below BBB- by Standard & Poor's (S&P) or Baa3 by Moody's Investors Service (Moody's) would require additional approval from the OPUC prior to our issuing additional debt.

The following table summarizes our current debt 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)	A+	A1
Senior unsecured (long-term debt)		A3
Corporate credit rating	A+	
Ratings outlook	Stable	Stable

The above 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 solely to facilitate an understanding of our liquidity and costs of funds and 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

For the six months ended June 30, 2010 or 2009, there are no long-term debt redemptions. In November 2009, $0.3 million of our 6.65 percent secured MTNs due 2027 were redeemed pursuant to a one-time put option. This one-time put option has now expired, and the $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

For long-term debt maturing over the next five years, see Part II, Item 7., "Results of Operations—Financial Condition—Contractual Obligations," in our 2009 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, 2010, cash flow from operating activities decreased $95.5 million compared to the same period in 2009. The significant factors contributing to changes in cash flow for the six months ended June 30, 2010 compared to the same period of 2009 are as follows:

42

Table of Contents

- a decrease of $52.3 million from changes in receivables primarily due to $35.3 million of customer refunds in June 2009 and higher receivable balances at the end of 2008 versus 2009;
- a decrease of $34 million from lower deferred gas cost savings which reflect actual gas prices compared to estimated gas prices embedded in customer rates;
- a decrease of $20.8 million in income taxes receivable as refunds were received in 2009 for bonus depreciation and a net operating loss carryover from 2008;
- an increase of $15 million from a smaller pension contribution in 2010 compared to 2009;
- an decrease of $13.7 million related to the change in gas inventories in 2009 due to the higher price of gas in 2008; and
- an increase of $10.1 million from the loss realized in 2009 on the settlement of our interest rate hedge (see Note 10).

In February 2009, the American Recovery and Reinvestment Act of 2009 (Act) was signed into law. This Act extended for another year the ability for businesses to take an additional first-year depreciation deduction equivalent to 50 percent of an asset's adjusted basis for qualified property purchased and placed in service during 2009. We estimate the bonus depreciation provision will defer the payment of approximately $13.0 million of federal income taxes during 2010 to future periods.

Investing Activities

Cash used in investing activities for the six months ended June 30, 2010 totaled $90.4 million, up from $58.6 million for the same period in 2009. Our capital expenditures were $125.9 million in the six months ended June 30, 2010, up $71.5 million from $54.4 million for the same period in 2009. Our utility capital expenditures decreased $8.9 million primarily due to completing our automated meter reading project in 2009 and our non-utility capital expenditures increased $80.4 million, primarily due to investments in Gill Ranch.

Restricted cash, which collateralizes equipment purchase contracts and bank loans for Gill Ranch, increased $45.4 million compared to 2009, primarily due to settling our cash collateralized loan in June 2010.

In 2010, utility capital expenditures are estimated to be between $80 and $90 million, and non-utility capital expenditures are expected to be between $120 and $145 million for business development projects that are currently in process (see "Strategic Opportunities," above).

Over the five-year period 2010 through 2014, utility capital expenditures are estimated at between $400 and $500 million. The estimated level of utility capital expenditures over the next five years reflects assumptions for customer growth, utility storage development at Mist, 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 2009 Form 10-K).

Our funding of the total cost for the current development at Gill Ranch is estimated to be between $185 million and $205 million. As of June 30, 2010, we have invested $145.3 million of equity funds in Gill Ranch. The remaining project cost is expected to be met from a combination of equity funds and debt, which will be non-recourse to NW Natural. We have not pledged any of our utility assets, nor have we provided any parent guarantees, toward Gill Ranch's obligations.

Table of Contents

In 2010, Palomar expects to continue working on the planning and permitting phase of the proposed pipeline while it evaluates the potential impacts of changes to project scope and timeline due to the bankruptcy filing by the company which had entered into a precedent agreement for a majority of the proposed pipeline's capacity. The total cost for planning and permitting, excluding shippers' credit support, is estimated to be between $40 million and $50 million, of which our ownership interest is 50 percent. The initial planning and permitting costs are being financed with equity funds from us and our partner, GTN, in PGH, and to a certain extent from shipper credit support (see discussion of shipper obligations below).

In April 2009, Palomar received $15.8 million from a letter of credit which had supported the majority shipper's obligations under a prior precedent agreement and were applied against Palomar project costs. The shipper provided additional collateral to secure its obligations under the current precedent agreement and to support a portion of the ongoing planning and permitting costs as the project developed. In May 2010, the majority shipper suspended operations and filed for bankruptcy protection. Palomar is in the process of determining the appropriate next steps with respect to its contract rights and the collateral. For more information, see Note 8 and "Strategic Opportunities—Pipeline Diversification," above.

Financing Activities

Cash used in financing activities in the six months ended June 30, 2010 totaled $15.2 million, down from cash used of $117 million for the same period in 2009. Our short-term debt balances increased $4.9 million in the six months ended June 30, 2010, compared to a decrease of $170.2 million for the same period in 2009, which was partially offset by our long-term debt issuance of $75 million in March 2009. We use long-term debt proceeds primarily to finance capital expenditures, refinance maturing short-term or redeem long-term debt maturities as well as for general corporate purposes.

Pension Funding Status

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans were underfunded by $83.9 million at December 31, 2009. In March 2010, we contributed $10 million to these plans, with a portion allocated to 2009 and 2010 plan years. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Note 6, 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 2009 Form 10-K.

We also contribute to a multiemployer pension plan (Western States Plan) pursuant to our collective bargaining agreement. Our total contribution to the Western States Plan in 2009 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, 2010 and 2009. See Note 6 for further discussion.

Ratios of Earnings to Fixed Charges

For the six and twelve months ended June 30, 2010 and the twelve months ended December 31, 2009, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 4.85, 3.84 and 3.86, 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. See Exhibit 12.

Table of Contents

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 accounting standards for contingencies (see Part II, Item 7., “Application of Critical Accounting Policies and Estimates,” in the 2009 Form 10-K). At June 30, 2010, we had a regulatory asset of $109.3 million for deferred environmental costs, which includes $41 million of total paid expenditures to date, $56.7 million for additional costs expected to be paid in the future and accrued interest of $11.6 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.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including, but not limited to, 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 2009 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-price financial swap and option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed or capped prices. These financial hedge contracts are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. At June 30, 2010 and 2009, notional amounts under these financial hedge contracts totaled $300.8 million and $308.4 million, respectively. If all of the commodity-based financial hedge contracts had been settled on June 30, 2010, a loss of about $50.3 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. As of June 30, 2010, all of our current outstanding financial hedge contracts mature on or before October 2012. The $50.3 million unrealized loss is an estimate of future cash flows based on forward market prices that are expected to be paid as follows: $35.6 million in the next 12 months and $14.7 million thereafter. The amount realized will change based on market prices at the time contract settlements are fixed.

Credit Risk

Credit exposure to suppliers. Certain suppliers that sell us gas have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers at liquid exchange points. We evaluate and monitor suppliers’ creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit or surety bonds, in case a supplier defaults. In the event of a supplier’s failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We believe these costs would be subject to the PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the monthly market index price tied to liquid exchange points, and we have significant storage flexibility, we believe that it is unlikely that a supplier default would have a material adverse effect on our financial condition or results of operations.

45

Table of Contents

Credit exposure to financial derivative counterparties. Based on estimated fair value at June 30, 2010, our overall credit exposure relating to commodity hedge contracts reflects an amount we owed of $50.3 million to our financial derivative counterparties. Our financial derivatives policy requires counterparties to have at least an 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. 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 cash collateral, letters of credit or guarantees as circumstances warrant. Our actual derivative credit risk exposure, which reflects amounts that financial derivative counterparties owe to us, is less than $0.1 million, and these amounts are under contracts that are expected to settle on or before October 2012.

The following table summarizes our overall credit exposure, based on estimated fair value, and the corresponding counterparty unsecured credit ratings. 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, 2010	June 30, 2009	December 31, 2009
AAA/Aaa	$ -	$ -	$ -
AA/Aa	(39,195)	(65,060)	(15,792)
A/A	(11,140)	(7,821)	-
BBB/Baa	-	-	-
Total	$ (50,335)	$ (72,881)	$ (15,792)

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 posting or calling for 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 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.

For the impact of new legislation on our derivatives, see Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Financial Condition—Liquidity and Capital Resources," above.

Table of Contents

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, 2010 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).

Table of Contents

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 2009 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 2009 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, 2010 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASE 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
04/01/10 - 04/30/10	2,728	$47.52	-	-
05/01/10 - 05/31/10	22,442	$46.74	-	-
06/01/10 - 06/30/10	2,071	$45.04	-	-
Total	27,241	$46.69	2,124,528	$ 16,732,648

(1) During the three months ended June 30, 2010, 23,798 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, 3,443 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, 2010, 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, 2011 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, 2010, no shares of our common stock were purchased pursuant to this program. Since the

program's inception in 2000 we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

Table of Contents

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 4, 2010

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

Table of Contents

NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX
To
Quarterly Report on Form 10-Q
For Quarter Ended
June 30, 2010

Exhibit Number	Document
12	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101*	The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.

* Users of this data are advised pursuant to Rule 401 of Regulation S-T that the financial information contained in these XBRL documents is unaudited and that these are not the official publicly filed financial statements of Northwest Natural Gas Company. In accordance with Rule 402 of Regulation S-T, the information in these exhibits shall not be deemed to be “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.