NORTHWEST NATURAL GAS CO
Form 10-Q
August 06, 2008
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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, 2008

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition period from __________ to __________

Commission File No. 1-15973

NORTHWEST NATURAL GAS COMPANY

(Exact name of registrant as specified in its charter)

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

220 N.W. Second Avenue, Portland, Oregon 97209

(Address of principal executive offices) (Zip Code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of accelerated filer, large 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 ¨

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

At July 31, 2008, 26,435,373 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

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NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended June 30, 2008

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Income

(Unaudited)

Thousands, except per share amounts	**Three Months Ended June 30, 2008**	**2007**	**Six Months Ended June 30, 2008**	**2007**
Operating revenues:				
Gross operating revenues	$ 191,254	$ 183,249	$ 578,948	$ 577,340
Less: Cost of sales	124,010	114,744	369,930	360,213
Revenue taxes	4,672	4,387	14,023	14,001
Net operating revenues	62,572	64,118	194,995	203,126
Operating expenses:				
Operations and maintenance	25,840	28,420	54,298	57,259
General taxes	6,722	5,351	14,856	13,168
Depreciation and amortization	17,957	16,972	35,662	33,757
Total operating expenses	50,519	50,743	104,816	104,184
Income from operations	12,053	13,375	90,179	98,942
Other income and expense - net	1,940	(481)	2,113	57
Interest charges - net of amounts capitalized	8,933	8,801	18,363	18,368
Income before income taxes	5,060	4,093	73,929	80,631
Income tax expense	1,763	1,476	27,464	29,939
Net income	$ 3,297	$ 2,617	$ 46,465	$ 50,692
Average common shares outstanding:				
Basic	26,421	26,999	26,415	27,114
Diluted	26,571	27,164	26,564	27,261
Earnings per share of common stock:				
Basic	$ 0.12	$ 0.10	$ 1.76	$ 1.87
Diluted	$ 0.12	$ 0.10	$ 1.75	$ 1.86

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	June 30, 2008 (Unaudited)	June 30, 2007 (Unaudited)	Dec. 31, 2007
Assets:			
Plant and property:			
Utility plant	$ 2,091,092	$ 2,002,460	$ 2,052,161
Less accumulated depreciation	637,680	595,195	615,533
Utility plant - net	1,453,412	1,407,265	1,436,628
Non-utility property	72,242	57,061	67,149
Less accumulated depreciation and amortization	8,537	7,392	7,904
Non-utility property - net	63,705	49,669	59,245
Total plant and property	1,517,117	1,456,934	1,495,873
Current assets:			
Cash and cash equivalents	5,242	4,899	6,107
Accounts receivable	43,718	45,656	69,442
Accrued unbilled revenue	19,685	18,434	78,004
Allowance for uncollectible accounts	(3,013)	(2,975)	(2,890)
Regulatory assets	5,748	22,438	17,598
Fair value of non-trading derivatives	54,867	4,538	2,903
Inventories:			
Gas	32,910	52,615	71,079
Materials and supplies	9,959	9,245	8,865
Prepayments and other current assets	11,516	10,186	25,569
Total current assets	180,632	165,036	276,677
Investments, deferred charges and other assets:			
Regulatory assets	173,321	186,578	175,938
Fair value of non-trading derivatives	9,218	1,388	324
Other investments	64,276	48,950	54,070
Other	11,417	9,015	11,179
Total investments, deferred charges and other assets	258,232	245,931	241,511
Total assets	$ 1,955,981	$ 1,867,901	$ 2,014,061

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	June 30, 2008 (Unaudited)	June 30, 2007 (Unaudited)	Dec. 31, 2007
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 333,619	$ 350,360	$ 331,595
Earnings invested in the business	293,313	262,209	266,658
Accumulated other comprehensive income (loss)	(2,483)	(2,292)	(3,502)
Total common stock equity	624,449	610,277	594,751
Long-term debt	512,000	517,000	512,000
Total capitalization	1,136,449	1,127,277	1,106,751
Current liabilities:			
Notes payable	67,700	42,100	143,100
Long-term debt due within one year	5,000		5,000
Accounts payable	75,786	66,254	119,731
Taxes accrued	8,727	16,101	13,137
Interest accrued	2,837	2,820	2,827
Regulatory liabilities	84,370	42,473	61,326
Fair value of non-trading derivatives	2,792	18,115	14,829
Other current and accrued liabilities	32,251	25,858	29,794
Total current liabilities	279,463	213,721	389,744
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	221,266	208,978	206,340
Regulatory liabilities	227,076	205,838	213,764
Pension and other postretirement benefit liabilities	43,513	55,533	41,619
Fair value of non-trading derivatives	2,732	6,585	3,758
Other	45,482	49,969	52,085
Total deferred credits and other liabilities	540,069	526,903	517,566
Commitments and contingencies (see Note 11)			
Total capitalization and liabilities	$ 1,955,981	$ 1,867,901	$ 2,014,061

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

Thousands	Six Months Ended June 30, 2008	2007
Operating activities:		
Net income	$ 46,465	$ 50,692
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	35,662	33,757
Deferred income taxes and investment tax credits	14,028	(2,051)
Undistributed gains from equity investments	(346)	(198)
Deferred gas savings (costs) - net	(26,873)	20,461
Gain on sale of non-utility investments	(1,737)	
Non-cash expenses related to qualified defined benefit pension plans	1,530	2,108
Deferred environmental costs	(4,131)	(4,069)
Income from life insurance investments	(978)	(905)
Deferred regulatory costs and other	(6,466)	(1,832)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	84,224	105,548
Inventories of gas, materials and supplies	37,075	16,268
Prepayments and other current assets	7,083	8,855
Accounts payable	(45,684)	(47,636)
Accrued interest and taxes	(4,400)	(5,233)
Other current and accrued liabilities	2,634	4,528
Cash provided by operating activities	138,086	180,293
Investing activities:		
Investment in utility plant	(41,338)	(40,845)
Investment in non-utility property	(5,110)	(14,378)
Proceeds from sale of non-utility investments	6,845	
Proceeds from life insurance	208	56
Contributions to non-utility equity investments	(3,000)	
Other	(4,286)	2,658
Cash used in investing activities	(46,681)	(52,509)
Financing activities:		
Common stock issued, net of expenses	2,589	1,389
Common stock repurchased		(23,631)
Long-term debt retired		(29,500)
Change in short-term debt	(75,400)	(58,000)
Cash dividend payments on common stock	(19,808)	(19,257)
Other	349	347
Cash used in financing activities	(92,270)	(128,652)
Decrease in cash and cash equivalents	(865)	(868)

Cash and cash equivalents - beginning of period		6,107		5,767
Cash and cash equivalents - end of period	$	5,242	$	4,899
Supplemental disclosure of cash flow information:				
Interest paid	$	18,424	$	18,652
Income taxes paid	$	14,800	$	33,000

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Financial Statements and New Accounting Standards

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), which primarily consist of our regulated gas distribution business, our regulated gas storage business including a wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), and other businesses including a wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and a 50 percent joint venture investment in a proposed natural gas transmission pipeline (Palomar) with TransCanada Gas Transmission Northwest (GTN).

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 2007 Annual Report on Form 10-K (2007 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

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

Certain prior year balances on our consolidated balance sheets 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.

New Accounting Standards

Adopted Standards

Fair Value Measurements. In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements, which is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement indicates, among other things, that a fair value measurement assumes that a transaction to sell an asset or transfer a liability occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability. SFAS No. 157 defines fair value based upon an exit price model.

Relative to SFAS No. 157, the FASB issued FASB Staff Positions (FSP) 157-1 and 157-2. FSP 157-1 amends SFAS No. 157 to exclude SFAS No. 13, Accounting for Leases, and its related interpretive accounting pronouncements that address leasing transactions. FSP SFAS No. 157-2 delays the effective date of the application of SFAS No. 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and liabilities except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis.

We adopted SFAS No. 157 as of January 1, 2008, with the exception of the application of the statement to nonfinancial assets and liabilities. Nonfinancial assets and liabilities for which we have not yet applied the provisions of SFAS No. 157 include asset retirement obligations initially measured at fair value. The adoption of SFAS No. 157, FSP SFAS No. 157-1 and FSP SFAS No. 157-2 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flow.

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Fair Value Option for Financial Assets and Liabilities. In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We have elected not to implement the fair value option for financial assets and liabilities as the majority of our assets and liabilities are regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC), both of which generally allow that we earn a reasonable return on invested capital based on original cost rather than current market value.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. On January 1, 2008, we adopted Emerging Issues Task Force (EITF) 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards, which provides the accounting requirements for recognizing income tax benefits received on dividends paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options, and how these benefits are charged to retained earnings under SFAS No. 123R, Share Based Payment. The adoption of EITF 06-11 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flow.

Offsetting Amounts Related to Certain Contracts. On January 1, 2008, we adopted FSP FASB Interpretation No. 39-1 (FSP FIN 39-1), Offsetting of Amounts Related to Certain Contracts. FSP FIN 39-1 requires disclosure when a reporting entity offsets fair value amounts from derivative instruments executed with the same counterparty under master netting arrangements. Our disclosures on FSP FIN 39-1 are included in Note 10. The adoption and implementation of FSP FIN 39-1 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flow.

Recent Accounting Pronouncements

Business Combinations. In December 2007, the FASB issued SFAS No. 141R, Business Combinations. This statement amends the principles and requirements for how an acquiror accounts for and discloses its business combinations as described under SFAS No. 141. SFAS No. 141R is effective for fiscal years and interim periods beginning after December 15, 2008. Based on our preliminary assessment, this statement is not expected to have a material effect on our financial condition, results of operations or cash flow.

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements. This statement amends the reporting requirements of Accounting Research Bulletin No. 51 for noncontrolling interests in subsidiaries to improve the relevance, comparability and transparency of the financial information disclosed. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. Based on the nature of this new statement and our current organizational structure, we currently have no additional required disclosures. The adoption of this statement it is not expected to have a material effect on our financial condition, results of operations or cash flow.

Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, Accounting for Derivative Instruments and Hedging Activities, which requires enhanced disclosures of derivative instruments and hedging activities. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008.

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SFAS No. 161 will expand current disclosures by adding qualitative disclosures about our hedging objectives and strategies, fair value gains and losses, and our credit-risk-related contingent features in derivative agreements. The disclosures are intended to provide an enhanced understanding of:

How and why we use derivative instruments;

How derivative instruments and related hedge items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and its related interpretations; and

How derivative instruments and related hedged items affect our financial condition, results of operations and cash flow.

As SFAS No. 161 relates only to disclosures, there will be no effect on our financial condition, results of operations or cash flow.

Share-Based Payment Transactions are Participating Securities. In June 2008, the FASB issued final FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. This statement requires nonforfeitable rights to dividends or dividend equivalents on unvested share-based payment to be included in the computation of earnings per share under the two-class method. This statement will be effective for fiscal years beginning after December 15, 2008. Based on our preliminary assessment, the adoption of FSP No. EITF 03-6-1 is not expected to have a material effect on our financial condition, results of operations or cash flow.

2. Segment Information

Our core business segment is the local regulated gas distribution business, also referred to as the utility, which involves the distribution and sale of natural gas. Another business segment, gas storage, represents natural gas storage services provided to intrastate and interstate customers and asset optimization services under a contract with an independent energy marketing company. Gas storage also includes Gill Ranch, our wholly-owned subsidiary, which was formed in 2007 to develop and operate an underground gas storage facility near Fresno, California. Gill Ranch is in the planning and permitting phase of development. The remaining business segment, Other, primarily consists of our wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including our equity investment in Palomar.

On April 23, 2008, NW Natural sold its investment in a Boeing 737-300 aircraft for approximately $6.2 million cash, plus accrued rents. We purchased the airplane in 1987 and leased it to Continental Airlines. As a result of the sale, we recognized an after-tax gain of $1.1 million in the second quarter of 2008.

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The following table presents information about the reportable segments. Inter-segment transactions are insignificant.

Thousands	Utility	Three Months Ended June 30, Gas Storage	Other	Total
2008				
Net operating revenues	$ 57,183	$ 5,339	$ 50	$ 62,572
Depreciation and amortization	17,633	324		17,957
Income (loss) from operations	7,451	4,907	(305)	12,053
Net income (loss)	(743)	2,488	1,552	3,297
2007				
Net operating revenues	$ 59,125	$ 4,948	$ 45	$ 64,118
Depreciation and amortization	16,749	223		16,972
Income from operations	8,865	4,499	11	13,375
Net income (loss)	(79)	2,663	33	2,617

Thousands	Utility	Six Months Ended June 30, Gas Storage	Other	Total
2008				
Net operating revenues	$ 184,562	$ 10,336	$ 97	$ 194,995
Depreciation and amortization	35,012	650		35,662
Income from operations	81,328	8,750	101	90,179
Net income	39,799	4,841	1,825	46,465
Total assets at June 30, 2008	$ 1,877,199	$ 67,198	$ 11,584	$ 1,955,981
2007				
Net operating revenues	$ 194,674	$ 8,358	$ 94	$ 203,126
Depreciation and amortization	33,312	445		33,757
Income from operations	91,460	7,440	42	98,942
Net income	46,029	4,458	205	50,692
Total assets at June 30, 2007	$ 1,808,089	$ 52,092	$ 7,720	$ 1,867,901

3. Capital Stock

At the annual meeting of shareholders, held on May 22, 2008, our shareholders approved an amendment to our Restated Articles of Incorporation increasing the total number of authorized shares of common stock from 60 million to 100 million. As of June 30, 2008, there were 26,435,373 shares outstanding.

We have a Board approved share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. On April 24, 2008, the Board extended the program through May 31, 2009 and confirmed its authorization to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the six months ended June 30, 2008, no shares of common stock were repurchased pursuant to this program. As of June 30, 2008, common stock repurchases under this program, since inception in 2000, totaled 2.1 million shares or $83.3 million.

4. Stock-Based Compensation

Our stock-based compensation plans consist of the Long-Term Incentive Plan (LTIP), the Restated Stock Option Plan (Restated SOP), the Employee Stock Purchase Plan (ESPP) and the Non-Employee Directors Stock Compensation Plan (NEDSCP). These plans are designed to promote stock ownership by employees and officers and, in the case of the NEDSCP, non-employee directors. For additional information on our stock-based compensation plans, see Part II, Item 8., Note 4, in the 2007 Form 10-K.

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Long-Term Incentive Plan. A total of 500,000 shares of NW Natural s common stock has been authorized for awards under the terms of the LTIP as stock bonus, restricted stock or performance-based stock awards. During the six months ended June 30, 2008, 48,500 performance-based shares were granted under the LTIP, based on target-level awards, with a weighted-average grant date fair value of $10.89 per share. No LTIP stock awards were granted after the first quarter of 2008. In February 2008, the Board of Directors amended and restated our Deferred Compensation Plan for Directors and Executives to eliminate the ability to defer any LTIP stock award payouts into cash accounts. Stock-based compensation related to the outstanding LTIP share awards was re-valued as of the amendment date, and the accounting for these awards was changed from the liability method to the equity method in accordance with SFAS No. 123R, Share Based Payment. The fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following weighted-average assumptions:

Stock price on valuation date	$ 43.29
Performance term (in years)	3.0
Quarterly dividends paid per share	$ 0.375
Expected dividend yield	3.4%
Dividend discount factor	0.9026

Restated Stock Option Plan. In February 2008, 114,050 stock options were granted under the Restated SOP, with an exercise price equal to the closing market price of our common stock on the date of grant, vesting over the four-year period following date of grant and a term of 10 years and 7 days. The fair value was estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

Risk-free interest rate	2.8%
Expected life (in years)	4.7
Expected market price volatility factor	18.4%
Expected dividend yield	3.5%
Forfeiture rate	3.8%

As of June 30, 2008, there was $0.8 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2011.

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5. Long-Term Debt

At June 30, 2008 and 2007 and December 31, 2007, we had outstanding long-term debt as follows:

Thousands	June 30, 2008 (Unaudited)	June 30, 2007 (Unaudited)	Dec. 31, 2007
Medium-Term Notes			
First Mortgage Bonds:			
6.50 % Series B due 2008	$ 5,000	$ 5,000	$ 5,000
4.11 % Series B due 2010	10,000	10,000	10,000
7.45 % Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	10,000	10,000
7.13 % Series B due 2012	40,000	40,000	40,000
8.26 % Series B due 2014	10,000	10,000	10,000
4.70 % Series B due 2015	40,000	40,000	40,000
5.15 % Series B due 2016	25,000	25,000	25,000
7.00 % Series B due 2017	40,000	40,000	40,000
6.60 % Series B due 2018	22,000	22,000	22,000
8.31 % Series B due 2019	10,000	10,000	10,000
7.63 % Series B due 2019	20,000	20,000	20,000
9.05 % Series A due 2021	10,000	10,000	10,000
5.62 % Series B due 2023	40,000	40,000	40,000
7.72 % Series B due 2025	20,000	20,000	20,000
6.52 % Series B due 2025	10,000	10,000	10,000
7.05 % Series B due 2026	20,000	20,000	20,000
7.00 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2028	10,000	10,000	10,000
7.74 % Series B due 2030	20,000	20,000	20,000
7.85 % Series B due 2030	10,000	10,000	10,000
5.82 % Series B due 2032	30,000	30,000	30,000
5.66 % Series B due 2033	40,000	40,000	40,000
5.25 % Series B due 2035	10,000	10,000	10,000
	517,000	517,000	517,000
Less long-term debt due within one year	5,000		5,000
Total long-term debt	$ 512,000	$ 517,000	$ 512,000

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6. Earnings Per Share

Basic earnings per share are computed based on the weighted average number of common shares outstanding during each period presented. Diluted earnings per share reflect the potential effects of the exercise of stock options. Diluted earnings per share are calculated as follows:

Thousands, except per share amounts	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Net income	$ 3,297	$ 2,617	$ 46,465	$ 50,692
Average common shares outstanding - basic	26,421	26,999	26,415	27,114
Additional shares for stock-based compensation plans	150	165	149	147
Average common shares outstanding - diluted	26,571	27,164	26,564	27,261
Earnings per share of common stock - basic	$ 0.12	$ 0.10	$ 1.76	$ 1.87
Earnings per share of common stock - diluted	$ 0.12	$ 0.10	$ 1.75	$ 1.86

For the three and six months ended June 30, 2008 and 2007, no common share equivalents were excluded from the calculation of diluted earnings per share because all common share equivalents were dilutive.

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7. Pension and Other Postretirement Benefits

The following tables provide the components of net periodic benefit cost for our qualified and non-qualified defined benefit pension plans and other postretirement benefit plans for the three and six months ended June 30, 2008 and 2007:

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	**2008**	**2007**	**2008**	**2007**
Service cost	$ 1,653	$ 2,159	$ 132	$ 147
Interest cost	4,303	3,992	349	320
Expected return on plan assets	(4,777)	(4,636)		
Amortization of loss	96	538		1
Amortization of prior service cost	313	246	50	50
Amortization of transition obligation			103	103
Net periodic benefit cost	1,588	2,299	634	621
Amount allocated to construction	(409)	(533)	(224)	(210)
Net amount charged to expense	$ 1,179	$ 1,766	$ 410	$ 411

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	**2008**	**2007**	**2008**	**2007**
Service cost	$ 3,308	$ 4,318	$ 265	$ 295
Interest cost	8,604	7,987	698	640
Expected return on plan assets	(9,554)	(9,272)		
Amortization of loss	192	1,077		2
Amortization of prior service cost	627	491	99	99
Amortization of transition obligation			206	206
Net periodic benefit cost	3,177	4,601	1,268	1,242
Amount allocated to construction	(788)	(1,048)	(431)	(412)
Net amount charged to expense	$ 2,389	$ 3,553	$ 837	$ 830

See Part II, Item 8., Note 7, in the 2007 Form 10-K for more information about our pension and other postretirement benefit plans.

Employer Contributions

During the six months ended June 30, 2008, we did not make and were not required to make cash contributions to our qualified non-contributory defined benefit pension plans, but cash contributions in the form of ongoing benefit payments of $1.4 million were made for our unfunded, non-qualified supplemental pension plans and other postretirement benefit plans. See Part II, Item 8., Note 7, in the 2007 Form 10-K for a discussion of estimated future payments.

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8. Comprehensive Income

Items that are excluded from net income and charged directly to common stock equity are included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in common stock equity is $2.5 million at June 30, 2008, which is related to employee benefit plan liabilities and changes in unrealized gains from derivatives. The following table provides a reconciliation of net income to total comprehensive income for the three and six months ended June 30, 2008 and 2007.

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	**2008**	**2007**	**2008**	**2007**
Net income	$ 3,297	$ 2,617	$ 46,465	$ 50,692
Amortization of employee benefit plan liability, net of tax	55	32	110	64
Change in unrealized gain from derivatives, net of tax	304		908	
Total comprehensive income	$ 3,656	$ 2,649	$ 47,483	$ 50,756

9. Fair Value of Financial Instruments

We use fair value measurements to record fair value adjustments to certain financial instruments and to determine fair value disclosures. As of June 30, 2008, we recorded our derivatives at fair value according to SFAS No. 157. As we elected not to implement SFAS No. 159, we did not measure our long-term debt at fair value (see Note 1).

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

Level 1: Valuation is based upon quoted prices for identical instruments traded in active markets;

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

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

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

The following table provides the fair value hierarchy of our derivative assets and liabilities as of June 30, 2008:

Thousands	**Fair Value Measurements at June 30, 2008**	
Hierarchy	**Description of Derivative Inputs**	**Fair Value, net**
Level 1	Quoted prices in active markets	$
Level 2	Significant other observable inputs	58,561
Level 3	Significant unobservable inputs	

$	58,561

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10. Use of Financial Derivatives

We enter into forward contracts and other related financial transactions that qualify as derivative instruments under SFAS No. 133, Accounting for Derivatives, as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133). We utilize derivative financial instruments primarily to manage commodity prices related to natural gas supply requirements and interest rates related to existing or anticipated debt issuances (see Part II, Item 8., Note 11, in the 2007 Form 10-K).

At June 30, 2008 and 2007 and December 31, 2007, unrealized gains and losses from mark-to-market valuations of our derivative instruments were reported as regulatory liabilities or regulatory assets because the realized gains or losses at settlement are included, or are expected to be included, in utility rates pursuant to regulatory deferral mechanisms (see Part II, Item 8., Note 1, in the 2007 Form 10-K). Estimated fair value of unrealized gains and losses were as follows:

	June 30, 2008		June 30, 2007		Dec. 31, 2007	
Thousands	**Current**	**Non-Current**	**Current**	**Non-Current**	**Current**	**Non-Current**
Fair Value Gain (Loss), net*:						
Natural gas commodity hedge contracts	$ 52,112	$ 7,844	$ (13,840)	$ (5,197)	$ (12,099)	$ (2,104)
Interest rate hedge contract		(1,358)				(1,330)
Foreign currency forward purchase contracts	(37)		263		173	
Total	$ 52,075	$ 6,486	$ (13,577)	$ (5,197)	$ (11,926)	$ (3,434)

* Fair value gains and losses include offsetting amounts if they are executed with the same counterparty under the same master netting arrangement.

In the three and six months ended June 30, 2008, we realized net gains of $17.0 million and $21.3 million, respectively, from the settlement of natural gas hedge contracts, which were recorded as reductions to the cost of gas, compared to net losses of $2.5 million and $10.0 million in the same periods of 2007, which were recorded as increases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts. The interest rate hedge contract outstanding at December 31, 2007 and June 30, 2008 qualifies as a cash flow hedge for accounting purposes, and changes in the value of this cash flow hedge are included in other comprehensive income, assuming 100 percent hedge effectiveness, or in regulatory assets or liabilities, assuming regulatory deferral to future utility rates. There were no realized gains or losses from the interest rate hedge during the three or six months ended June 30, 2008.

As of June 30, 2008, all outstanding natural gas hedge contracts are scheduled to mature on or before October 31, 2010. The maturity date for our interest rate swap contract is September 30, 2018. However, we expect to settle this contract concurrent with our next long-term debt issuance, which is expected to occur in the second half of 2008.

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 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 be reasonably estimated. See Part II, Item 8., Note 12, in the 2007 Form 10-K. The status of each site currently under investigation is provided below.

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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. We have a net liability of $20.5 million at June 30, 2008 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 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 working with the ODEQ to develop a study of manufactured gas plant wastes on the uplands at this site. The net liability at June 30, 2008 for the Siltronic site is $1.2 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 be estimated.

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes the area adjacent to the Gasco and Siltronic sites. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS), completion of which is currently expected in 2009. 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 2007, we received a revised estimate and updated our estimate for additional expenditures related to RI/FS development and environmental remediation. As of June 30, 2008, we have a net liability of $13.3 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 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 the removal of the tar deposit in the Portland Harbor in October 2005, and on November 5, 2005 the EPA approved the completed project. The total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $10.8 million. To date, we have paid $9.9 million on work related to the removal of the tar deposit. As of June 30, 2008, we have a net liability for $0.9 million remaining for our estimate of ongoing costs related to the 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 2007, we received notice that this site was added to the ODEQ s list of sites where releases of hazardous substances have been confirmed and its list where additional investigation or cleanup is necessary. As of June 30, 2008, we have recorded an estimated liability of $0.5 million for investigation at this site. We cannot reasonably estimate a range of liability until studies are completed.

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Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. Although it is 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. Until the results of that sampling are evaluated, additional liabilities cannot be reasonably estimated.

Oregon Steel Mills site. See Legal Proceedings, below.

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at June 30, 2008 and 2007 and December 31, 2007:

	Current Liabilities			Non-Current Liabilities		
	June 30,		Dec. 31,	June 30,		Dec. 31,
Thousands	**2008**	**2007**	**2007**	**2008**	**2007**	**2007**
Gasco site	$ 8,122	$ 3,775	$ 6,901	$ 12,406	$ 17,988	$ 14,342
Siltronic site	1,211	810				1,540
Portland Harbor site	1,348	1,507		12,864	10,160	14,821
Central Service Center site		535		529		529
Front Street site					1,200	
Other sites				83	84	167
Total	$ 10,681	$ 6,627	$ 6,901	$ 25,882	$ 29,432	$ 31,399

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the OPUC approved our request for deferral of environmental costs associated with several sites. On May 6, 2008, an extension of the original deferral was approved by the OPUC allowing us to defer and seek recovery of unreimbursed environmental costs incurred through January 25, 2009 in a future general rate case. Beginning in 2006, the OPUC authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. As of June 30, 2008, we have paid a cumulative total of $27.5 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, we have recognized a total of $68.9 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $32.3 million has been spent to date and $36.6 million is reported as an outstanding liability. At June 30, 2008, we had a regulatory asset of $64.2 million, which includes $27.5 million of total paid expenditures to date, $32.1 million for additional environmental costs expected to be paid in the future and accrued interest of $4.6 million. We believe the recovery of these deferred charges is probable through the regulatory process. We intend to pursue recovery of an insurance receivable and environmental regulatory deferrals from insurance carriers under our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of most of our environmental costs probable based on a combination of factors including: a review of the terms of our insurance policies, the financial condition of the insurance companies providing coverage, a review of successful claims filed by other utilities with similar gas manufacturing facilities, and Oregon law that allows an insured party to seek recovery of all sums from one insurance company. We have initiated settlement discussions with a majority of our insurers but continue to anticipate that our overall insurance recovery effort will extend over several years.

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 matters by individual size at June 30, 2008 and 2007 and December 31, 2007:

	Non-Current Regulatory Assets		
	June 30,		Dec. 31,
Thousands	2008	2007	2007
Gasco site	$ 29,898	$ 27,187	$ 29,042
Siltronic site	2,247	1,227	2,227
Portland Harbor site	31,092	26,676	30,869
Central Service Center site	545	545	545
Front Street site	11	1,211	
Other sites	366	278	371
Total	$ 64,159	$ 57,124	$ 63,054

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, including the matter described below, 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.

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

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

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

The following is management s assessment of Northwest Natural Gas Company s (NW Natural) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the three and six months ended June 30, 2008 and 2007. Unless otherwise indicated, references in this discussion to Notes are to the Notes to Consolidated Financial Statements in this report.

The consolidated financial statements include the accounts of NW Natural and its wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and a 50 percent joint venture investment in a proposed natural gas pipeline (Palomar) with TransCanada Gas Transmission Northwest (GTN). These accounts principally consist of our regulated local gas distribution business, our regulated 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 gas distribution business, and the term non-utility is used to describe our gas storage business (gas storage) and our other regulated and non-regulated investments and business activities (other segment) (see Strategic Opportunities, below, and Note 2).

Certain prior year balances on our consolidated balance sheets 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 our financial condition or cash flows.

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 the 2007 Form 10-K).

Executive Summary

Highlights from the second quarter of 2008 include:

- Consolidated net income increased 26 percent over the second quarter of 2007, from \$2.6 million to \$3.3 million;
- Utility net operating revenues (margin) decreased by \$1.9 million, but the margin loss was more than offset by lower utility operations and maintenance expense which decreased by \$2.6 million or 9 percent;
- The sale of our investment in a Boeing 737-300 aircraft for an after-tax gain of \$1.1 million;
- Customer growth at the utility was a net gain of 16,143 over the last 12 months, for an annual growth rate of 2.5 percent; and
- Cash flow from operations decreased 23 percent for the six months ended June 30, 2008, from \$180.3 million to \$138.1 million, primarily reflecting higher gas purchase costs, of which a majority are deferred under our purchased gas adjustment mechanism for future recovery through customer billing rates beginning November 1, 2008.

Issues, Challenges and Performance Measures

Managing the business in a period of higher gas prices. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility s core (residential, commercial and industrial firm) customers. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon our core utility s gas load forecast. We believe we have sufficient supplies of natural gas to meet the needs of our core customers, but we are not able to predict future gas costs.

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Gas costs above those set in our Purchased Gas Adjustment (PGA) tariff are likely to negatively impact earnings under the PGA incentive gas cost sharing mechanism and could affect our competitive advantage and earnings outlook. A continued increase in gas prices could also affect our ability to attract and retain new residential and commercial customers, increase our bad debt expense and result in industrial customers shifting their businesses energy needs to alternative fuel sources. We are currently in a proceeding before the Oregon Public Utility Commission (OPUC) to seek modifications to our PGA mechanism in an effort to manage gas price risks for our customers and shareholders. We also continue to develop new gas acquisition strategies to manage gas prices and to efficiently meet customer demand.

Customer growth. Our growth is largely driven by new residential construction, and while we expect to continue with a customer growth rate above the national average for local gas distribution companies due to the growing Pacific Northwest housing market relative to housing markets in other parts of the nation, we have experienced a slowdown in new construction which is expected to continue at least through 2008. Based on the current outlook for housing starts, we anticipate our annual growth rate could decline further in 2008. The current period slowdown in new construction was partially offset by a modest rebound in residential conversions from other fuels to natural gas. For the 12 months ended June 30, 2008, our annual growth rate was 2.5 percent, compared to 2.6 percent for the comparable period ended June 30, 2007. A prolonged slowdown in residential new construction could adversely impact our future results of operations (see Part II, Item 7., Executive Summary Issues, Challenges and Performance Measures, in the 2007 Form 10-K).

Strategic Opportunities

Business Process Improvements. To address our economic and competitive challenges, we continue to refine our new operating model as well as pursue cost saving investments. In the first six months of 2008, we implemented the first phase of our new integrated information system and began work on a second phase which is expected to be completed by early 2009. In 2006, we initiated a project to automate the reading of gas meters on approximately one-half of our customers meters. The meters equipped with this technology transmit usage data to receiving devices located in our vehicles as they are driven in the area, eliminating the need for manual reading of customers meters. In the second quarter of 2008, we initiated a project to automate the reading of gas meters for our remaining customers. We expect to seek regulatory recovery of the estimated $30 million project cost. These technology investments and other initiatives are expected to facilitate process improvements and overall operational efficiencies throughout NW Natural. For more information regarding our redesign efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

Pipeline Diversification. In September 2006, we announced that we were evaluating a possible equity investment in Palomar, which is a natural gas transmission pipeline that would connect GTN s interstate transmission line to our local gas distribution system. Palomar is intended to diversify our gas supply and delivery options and to enhance reliable service to our customers by providing an alternate transportation path for, and potentially an alternative gas supply source to, gas purchases in Alberta, Canada and in the U.S. Rocky Mountain regions. Plans for Palomar also include the possible delivery of supplies from one of several liquefied natural gas (LNG) facilities that are currently proposed to be built on the Columbia River. The planning and permitting phase of Palomar is expected to occur through 2009. We, along with GTN, will determine at a later date whether to proceed with development of Palomar beyond the permitting phase. If constructed, the most recent cost estimate for the entire 220-mile pipeline is between $600 million and $700 million, of which our share would be between approximately $300 million and $350 million. For more information regarding our pipeline diversification efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

Gas Storage Development. In September 2007, we announced a joint project with Pacific Gas & Electric Company to develop an underground natural gas storage facility near Fresno, California. We formed Gill Ranch to develop and operate the facility. Based on a strong level of interest from prospective customers in response to an open season to gauge interest in the storage facility, which was conducted from October 2007 to December 2007, on July 29, 2008 we filed an application with the California Public Utilities Commission for a Certificate of Public Convenience and Necessity. We estimate our share of the total cost for the initial development to be about $160 million between the periods 2008-2010, which represents 75 percent of the estimated phase one project costs. For more information regarding our gas storage development efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

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Earnings and Dividends

Three months ended June 30, 2008 compared to June 30, 2007:

Net income was $3.3 million, or 12 cents per share, for the three months ended June 30, 2008, compared to $2.6 million, or 10 cents per share, for the same period last year.

The primary factors contributing to increased second quarter earnings were:

- a $4.4 million net increase in utility margin from increased sales to residential and commercial customers, after weather and decoupling mechanism adjustments, due to customer growth and colder weather than the same period last year (see Results of Operations Comparison of Utility Operations, below);
- a $1.1 million increase in other income after-tax from a gain on sale of our investment in an aircraft; and
- a $2.6 million decrease in operations and maintenance expense primarily due to lower payroll related expenses including incentive accruals.

Partially offsetting the above positive factors were:

- a $5.5 million current period loss in margin from regulatory sharing of gas cost increases, compared to a gain in margin of $0.8 million in the second quarter of 2007 from gas cost savings;
- a $0.7 million decrease in margin from a regulatory adjustment for income taxes paid; and
- a $1.4 million increase in general tax expenses from higher regulatory fees and property taxes.

Six months ended June 30, 2008 compared to June 30, 2007:

Net income was $46.5 million, or $1.75 per share, for the six months ended June 30, 2008, compared to $50.7 million, or $1.86 per share, for the same period last year.

The primary factor contributing to lower year-to-date earnings was:

- a $5.8 million loss in margin from regulatory sharing of gas cost increases, compared to a gain in margin of $10.6 million in the first six months of 2007 from gas cost savings.

Partially offsetting the above factor reducing earnings were:

- a $6.1 million net increase in utility margin from increased sales to residential and commercial customers, after weather and decoupling mechanism adjustments, due to customer growth and colder weather than 2007;

a $3.0 million decrease in operations and maintenance expense primarily due to lower payroll related expenses including incentive accruals;

a $1.1 million increase in other income after-tax from a gain on sale of our investment in an aircraft;

a $0.4 million increase in net income from gas storage operations; and

a $2.5 million decrease in income tax expense related to lower taxable income.

Dividends paid on our common stock were 37.5 cents per share and 35.5 cents per share in the three months ended June 30, 2008 and 2007, respectively, and 75 cents per share and 71 cents per share in the six months ended June 30, 2008 and 2007, respectively. In July 2008, the Board of Directors declared a quarterly dividend on our common stock of 37.5 cents per share payable on August 15, 2008. The current indicated annual dividend rate is $1.50 per share.

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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, unbilled revenues and regulatory adjustment for income taxes paid;
- derivative instruments and hedging activities;
- pensions;
- income taxes; and
- environmental contingencies.

There have been no material changes to the information provided in the 2007 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 2007 Form 10-K). Management has discussed the estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board.

Within the context of our critical accounting policies and estimates, management is not currently 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 subject to regulation with respect to, among other matters, rates, and systems of accounts by the OPUC, the Washington Utilities and Transportation Commission (WUTC) and the Federal Energy Regulatory Commission. The OPUC and WUTC also regulate our issuance of securities. Typically, about 90 percent of our utility gas deliveries and operating revenues are derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the pace of continued growth in the residential and commercial markets 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 2007 Form 10-K.

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At June 30, 2008 and 2007 and at December 31, 2007, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		
	June 30,		Dec. 31,
Thousands	**2008**	**2007**	**2007**
Regulatory assets:			
Pension and other postretirement benefit obligations(1)	$ 1,912	$ 3,567	$ 1,912
Unrealized loss on non-trading derivatives(2)	2,792	17,429	14,788
Other	1,044	1,442	898
Total regulatory assets	$ 5,748	$ 22,438	$ 17,598
Regulatory liabilities:			
Gas costs payable	$ 24,307	$ 28,380	$ 46,153
Unrealized gain on non-trading derivatives(2)	53,999	4,538	2,903
Other	6,064	9,555	12,270
Total regulatory liabilities	$ 84,370	$ 42,473	$ 61,326

	Non-Current		
	June 30,		Dec. 31,
Thousands	**2008**	**2007**	**2007**
Regulatory assets:			
Unrealized loss on non-trading derivatives(2)	$ 2,732	$ 6,585	$ 3,758
Income tax asset	69,547	68,086	68,649
Pension and other postretirement benefit obligations(1)	26,203	49,088	27,152
Environmental costs - paid(3)	32,087	23,183	27,956
Environmental costs - accrued but not yet paid(3)	32,072	33,941	35,098
Other	10,680	5,695	13,325
Total regulatory assets	$ 173,321	$ 186,578	$ 175,938
Regulatory liabilities:			
Gas costs payable	$ 1,263	$ 5,859	$ 6,290
Unrealized gain on non-trading derivatives(2)	9,218	1,388	324
Accrued asset removal costs	214,044	196,159	204,886
Other	2,551	2,432	2,264
Total regulatory liabilities	$ 227,076	$ 205,838	$ 213,764

(1) Pension and other postretirement benefit obligations are approved for regulatory deferral based on Statement of Financial Accounting Standards (SFAS) No. 87 and SFAS No. 106 expense included in customer rates (see Part II, Item 8., Note 7, in the 2007 Form 10-K).

(2) Unrealized gains or losses on non-trading derivatives do not earn a rate of return or a carrying charge. These amounts, when realized at settlement, are recoverable through utility rates as part of our PGA.

(3)

Environmental costs are related to sites that are approved for regulatory deferral (see Note 11). We earn an authorized rate of return as a carrying charge on amounts paid; amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contractual arrangements to hedge the purchase price 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. Under the current PGA mechanisms, we collect an amount for purchased gas costs based on estimates included in rates. If the actual purchased gas costs differ

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from the estimated amounts included in rates, then we are required to defer that difference and pass it on to customers as an adjustment to future rates. As part of an incentive mechanism in Oregon, only 67 percent of the difference is deferred such that the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower purchased gas costs. In Washington, the PGA deferral is 100 percent of the higher or lower actual purchased gas costs.

The OPUC is currently conducting a formal review of PGA mechanisms used by natural gas distribution companies in Oregon. On May 2, 2008, NW Natural, along with the OPUC staff, Avista Corporation, Cascade Natural Gas, and Northwest Industrial Gas Users, filed a stipulation with the OPUC to settle certain issues related to the incentive mechanism of the gas utilities annual PGA. The incentive mechanism proposed in the stipulation includes an annual embedded cost of gas, the selection and application of sharing levels, and an annual earnings test, much like the current PGA mechanism. However, in addition to the annual benchmark, there is also a monthly benchmark against which both the embedded cost of gas and actual monthly gas costs would be compared. Also, depending on the sharing percentage that the utility elected (67/33, 80/20, or 90/10), the excess earnings threshold would range from 175 to 100 basis points above our authorized return on equity (see Excess Earnings Test, below). The stipulation is contested, and briefs on the matter will be filed in August. We have requested a decision by October 1, 2008 so that changes to our PGA can be implemented at the start of the next PGA year on November 1, 2008.

If it appears that the proposed PGA will not be adopted and implemented by November 1, 2008, we will likely either request an interim mechanism for the coming PGA year or increase our hedged position for the coming PGA year to levels higher than our current target of 75 percent.

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the OPUC approved our request for deferral of environmental costs associated with several sites. Beginning in 2006, the OPUC authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. On May 6, 2008, an extension of the original deferral including the authorization to accrue interest on the deferred environmental cost balances was approved by the OPUC allowing us to defer and seek recovery of unreimbursed environmental costs incurred through January 25, 2009 in a future general rate case. As of June 30, 2008, we have paid a cumulative total of $27.5 million relating to the named sites since the effective date of the deferral authorization.

Excess Earnings Test. The OPUC has a formalized process to test for excess utility earnings annually. We are authorized to retain all of our earnings up to a threshold level equal to our authorized return on equity of 10.2 percent plus 300 basis points. One-third of any earnings above that level will be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year depending on movements in long-term interest rates. For 2007, the threshold after adjustment was 13.40 percent. Based on the company s 2007 filed earnings report, the OPUC determined the company did not exceed this threshold. Therefore, no amounts need to be returned to customers. Adoption of the proposed changes to the PGA mechanism described in Purchased Gas Adjustment, above, would change our annual excess earnings test. In Washington, we are not subject to an annual excess earnings test and 100 percent of all prudently incurred gas costs are passed through to customers in rates.

Integrated Resource Planning. The OPUC and WUTC have implemented integrated resource planning (IRP) processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. We filed our IRP with the OPUC on April 14, 2008 and filed an update to our IRP with the WUTC on April 15, 2008. Elements of these plans include:

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

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Although the OPUC s order acknowledging the IRP does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. We expect an order from the OPUC in the third quarter of 2008.

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved the accounting treatment and cost recovery for our transmission pipeline integrity management program, a program mandated by the Pipeline Safety Improvement Act of 2002 and the related rules adopted by the U.S. Department of Transportation s Pipeline and Hazardous Materials Safety Administration. We classify our costs as either capital expenditures or regulatory assets, accumulate the costs over each 12 months ending September 30, and recover the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. The accounting and rate treatment for these costs extends through September 30, 2008 and management intends to seek approval of an extension of such treatment after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

In March 2008, the OPUC and WUTC approved our request to waive certain maintenance activities in connection with our investigation of some potentially defective valves. We are requesting recovery of remediation costs related to these valves in Oregon through our pipeline integrity management program. We expect to complete the investigation and develop our remediation plan by the third quarter of 2008.

Distribution Integrity Management Program. On June 25, 2008, the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Notice of Proposed Rulemaking for the Distribution Integrity Management Program (DIMP) Rule. The DIMP Rule would require operators of natural gas distribution pipeline systems to develop and implement integrity management programs for the distribution infrastructure, similar to the transmission integrity management requirements mandated as described above. PHMSA is expected to finalize the DIMP Rule by the end of 2008. If approved, we expect to seek approval for deferral accounting treatment and recovery of these costs in future rates from the OPUC and WUTC.

Washington General Rate Case. On March 28, 2008, we filed a request for a 4.8 percent margin increase in Washington as part of a general rate case. The last general rate increase in Washington was approved in 2004. The rate increase is requested to cover increased operating costs and investments in our distribution system. In this rate filing, we have also proposed a conservation decoupling mechanism that mirrors the mechanism that has been in effect in Oregon since 2002.

Rate Adjustment for Income Taxes Paid and Interstate Storage Credits. In June 2008, $1.9 million was collected from customers, representing the 2006 surcharge for an adjustment for income taxes paid. The surcharge was included in operating revenues from residential, commercial and industrial customers (see Comparison of Utility Operations Regulatory Adjustment for Income Taxes Paid, below), but it was more than offset by a refund to customers of $10.3 million from a sharing mechanism for interstate storage revenues.

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Comparison of Utility Operations

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

Thousands, except degree day and customer data	Three months ended June 30, 2008	Three months ended June 30, 2007	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	78,444	60,284	18,160
Commercial sales	52,161	42,570	9,591
Industrial - firm sales	10,556	11,692	(1,136)
Industrial - firm transportation	41,868	35,917	5,951
Industrial - interruptible sales	21,799	20,760	1,039
Industrial - interruptible transportation	57,784	63,177	(5,393)
Total utility volumes sold and delivered	262,612	234,400	28,212
Utility operating revenues - dollars:			
Residential sales	$ 95,660	$ 86,106	$ 9,554
Commercial sales	53,385	50,808	2,577
Industrial - firm sales	9,531	12,140	(2,609)
Industrial - firm transportation	1,643	1,470	173
Industrial - interruptible sales	16,011	17,595	(1,584)
Industrial - interruptible transportation	1,936	2,027	(91)
Regulatory adjustment for income taxes paid (1)	(673)		(673)
Other revenues	8,366	8,098	268
Total utility operating revenues	185,859	178,244	7,615
Cost of gas sold	124,004	114,732	(9,272)
Revenue taxes	4,672	4,387	(285)
Utility margin	$ 57,183	$ 59,125	$ (1,942)
Utility margin: (2)			
Residential sales	$ 44,328	$ 36,204	$ 8,124
Commercial sales	18,713	15,004	3,709
Industrial - sales and transportation	7,054	7,481	(427)
Miscellaneous revenues	1,480	1,341	139
Gain (loss) from gas cost incentive sharing	(5,471)	862	(6,333)
Other margin adjustments	13	(951)	964
Margin before regulatory adjustments	66,117	59,941	6,176
Weather normalization mechanism	(6,184)	(1,562)	(4,622)
Decoupling mechanism	(2,077)	746	(2,823)
Regulatory adjustment for income taxes paid (1)	(673)		(673)
Utility margin	$ 57,183	$ 59,125	$ (1,942)
Customers - end of period:			
Residential customers	594,121	578,957	15,164
Commercial customers	61,859	60,743	1,116
Industrial customers	804	941	(137)

Total number of customers - end of period	656,784	640,641	16,143
Actual degree days	860	698	
Percent colder (warmer) than average [3]	26%	2%	

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Thousands, except degree day data	Six months ended June 30, 2008	2007	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	260,812	223,181	37,631
Commercial sales	159,117	139,374	19,743
Industrial - firm sales	25,098	27,609	(2,511)
Industrial - firm transportation	90,854	79,388	11,466
Industrial - interruptible sales	47,841	46,424	1,417
Industrial - interruptible transportation	128,166	130,915	(2,749)
Total utility volumes sold and delivered	711,888	646,891	64,997
Utility operating revenues - dollars:			
Residential sales	$ 321,343	$ 313,244	$ 8,099
Commercial sales	168,349	168,850	(501)
Industrial - firm sales	23,353	28,795	(5,442)
Industrial - firm transportation	3,229	2,968	261
Industrial - interruptible sales	35,692	39,726	(4,034)
Industrial - interruptible transportation	4,031	4,120	(89)
Regulatory adjustment for income taxes paid (1)	382		382
Other revenues	12,122	11,166	956
Total utility operating revenues	568,501	568,869	(368)
Cost of gas sold	369,916	360,194	(9,722)
Revenue taxes	14,023	14,001	(22)
Utility margin	$ 184,562	$ 194,674	$ (10,112)
Utility margin: (2)			
Residential sales	$ 131,920	$ 117,240	$ 14,680
Commercial sales	53,347	47,342	6,005
Industrial - sales and transportation	15,385	15,860	(475)
Miscellaneous revenues	3,208	2,980	228
Gain (loss) from gas cost incentive sharing	(5,794)	10,636	(16,430)
Other margin adjustments	329	226	103
Margin before regulatory adjustments	198,395	194,284	4,111
Weather normalization mechanism	(13,732)	(1,454)	(12,278)
Decoupling mechanism	(483)	1,844	(2,327)
Regulatory adjustment for income taxes paid (1)	382		382
Utility margin	$ 184,562	$ 194,674	$ (10,112)
Actual degree days	2,840	2,550	
Percent colder (warmer) than average (3)	11%	0%	

(1) Regulatory adjustment for income taxes paid is described below under Regulatory Adjustment for Income Taxes Paid.

(2) Amounts reported as margin for each category of customers are net of demand charges and revenue taxes.

(3) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

Our utility results are affected by, among other things, customer growth and 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 that contributes to changes in margin based on changes in residential and commercial customer consumption, and we have a weather normalization mechanism that adjusts customer bills up or down based on the estimated margin impact 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 2007 Form 10-K). Both mechanisms are designed to reduce the volatility of our utility earnings.

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Three months ended June 30, 2008 compared to June 30, 2007:

Utility operations resulted in a net loss of $0.7 million, or 3 cents per share, in the second quarter of 2008 compared to a net loss of $0.1 million, or less than 1 cent per share, in 2007. Net income from utility operations is typically a small net gain or loss during the second quarter each year because of the reduced use of natural gas in the spring and early summer. Colder weather in the second quarter of 2008 and customer growth contributed to higher volumes and margins from our residential and commercial sectors. However, the margin gains from gas sales were more than offset by losses from our regulatory sharing of higher gas costs (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, while total utility margin decreased by 3 percent primarily due to a $5.5 million loss from our regulatory sharing of gas costs.

Six months ended June 30, 2008 compared to June 30, 2007:

In the first half of 2008, utility operations contributed net income of $39.8 million, or $1.50 per share, compared to $46.0 million, or $1.69 per share in 2007. Total utility volumes sold and delivered in the first half of this year increased by 10 percent over last year, while total utility margin decreased by 5 percent primarily due to a $16.4 million swing in margin from the regulatory sharing of gas costs.

Volume increases in the three and six months ended June 30, 2008 were due mainly to weather that was colder than 2007 and residential and commercial customer growth, which slowed but remained relatively strong with a net increase of 16,143 customers since June 30, 2007, or an annual growth rate of 2.5 percent. Our annual growth rate remains above the national average for local gas distribution companies, despite recent economic conditions that have slowed the level of new construction in our service territory. The margin decrease in the first half of this year was driven by a $5.8 million loss from our regulatory sharing of higher gas costs compared to a $10.6 million gain from our share of significant gas cost savings last year (see Executive Summary Issues, Challenges and Performance Measures, above, and Cost of Gas Sold, below).

Residential and Commercial Sales

Residential and commercial sales markets are impacted by seasonal weather patterns, energy prices, competition from alternative energy sources and economic conditions in our service areas. 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 the weather normalization mechanism in Oregon where about 90 percent of our customers are served. This mechanism does not cover any industrial customers or the approximately 10 percent of our eligible residential and commercial customers who have opted out of the mechanism. In Oregon, we also have a conservation decoupling 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 discourage customers from conserving energy. 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, the mechanisms do not fully insulate the utility from earnings volatility due to weather and conservation. See the tables above for the adjustments to utility margin revenues from the weather normalization and decoupling mechanisms for the three and six months ended June 30, 2008 and 2007.

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Three months ended June 30, 2008 compared to June 30, 2007:

The primary factors affecting residential and commercial volumes and operating revenues in the second quarter this year over last year include:

- 27 percent higher sales volumes and 9 percent higher net operating revenues as a result of weather that was 23 percent colder than last year; and
- operating revenues from higher sales volumes which were partially offset by lower billing rates, which reflect the lower gas costs set in the PGA effective November 1, 2007, and adjustments for the weather normalization mechanism (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2007 Form 10-K).

Six months ended June 30, 2008 compared to June 30, 2007:

The primary factors affecting residential and commercial volumes and operating revenues in the first half of this year over last year include:

- 16 percent higher sales volumes and 2 percent higher net operating revenues as a result of customer growth and weather that was 11 percent colder than last year; and
- operating revenues from higher sales volumes which were partially offset by lower billing rates, which reflect lower gas costs set in the PGA effective November 1, 2007 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2007 Form 10-K).

Utility operating revenues include accruals for unbilled revenues (gas delivered but not yet billed to customers) based on estimates of gas deliveries from that month s meter reading dates to month end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenues at the end of each month. At June 30, 2008, accrued unbilled revenue was $19.7 million, compared to $18.4 million at June 30, 2007, with the increase reflecting customer growth and colder weather toward the end of the second quarter of 2008 as compared to 2007.

Industrial Sales and Transportation

Industrial operating revenues include the commodity cost component of gas sold to sales service customers but not transportation-only customers. Therefore, industrial customer switching between sales service and transportation service can cause swings in operating revenues but generally our margins are not affected because we do not mark up the cost of gas. As such, we believe margin is a better measure of performance for the industrial sector.

Three months ended June 30, 2008 compared to June 30, 2007:

Total volumes delivered to industrial sales and transportation customers increased 0.5 million therms, or less than 1 percent, in the second quarter of 2008 as compared to the same period in 2007. The increase in volume was primarily due to additional load from some large customers, which are billed at lower margins. This was partially offset by other customers that cut back on their usage or shut-down operations temporarily in response to higher prices and a slowdown in their businesses. Margins were down by $0.4 million, or 6 percent, over last year. We expect this portion of our customer base will continue to be challenged by the high energy prices.

Six months ended June 30, 2008 compared to June 30, 2007:

Total volumes delivered to industrial sales and transportation customers increased 7.6 million therms, or 3 percent, in the first half of 2008 as compared to the same period in 2007. Utility margin related to these customers was down $0.5 million, or 3 percent, over last year, primarily due to customer slowdowns and cutbacks for the current three month period, as discussed above.

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Regulatory Adjustment for Income Taxes Paid

The Oregon legislature passed legislation, effective January 1, 2006, intended to ensure that regulated utility operations do not collect in rates more income taxes than they actually pay to taxing authorities. Under this legislation, if we pay more income taxes than we actually collect from our Oregon utility customers, in accordance with our most recent general rate case, then we are required to record a surcharge due from our Oregon utility customers. Conversely, if we pay less in income taxes than we actually collect from our Oregon utility customers, in accordance with our most recent rate case, or if our consolidated taxes paid are less than the taxes we collect from our Oregon utility customers, then we are required to record a refund due to our Oregon utility customers. For the 2006 tax year, we filed to recover $1.7 million through a surcharge to our Oregon utility customers. This surcharge was primarily driven by higher income taxes paid on gains from gas cost savings from our PGA incentive sharing mechanism in 2006 and strong operating results. The OPUC approved our filing, and we collected a total of $1.9 million, representing a surcharge of $1.7 million plus accrued interest of $0.2 million, from our customers in June 2008. This surcharge was included in our operating revenues from residential, commercial and industrial sales for the three and six months ended June 30, 2008.

As described in Part I, Item 2., Issues, Challenges, and Performance Measures, gas costs above or below those set in our PGA incentive gas cost sharing mechanism may cause us to recognize additional expense or income, and consequently affect the amount of income tax we actually pay. Based on our operating results through June 30, 2008, we have recorded an estimated surcharge of $0.2 million for the 2008 tax year to date. A total surcharge of $0.4 million was included in margin for the six months ended June 30, 2008, reflecting the current year s estimated accrual plus a true-up adjustment for the 2006 and 2007 tax years. Although we did not record an estimated surcharge (or refund) in our results of operations for the three and six month periods ended June 30, 2007 because the administrative rules regarding this legislation were not final and adjustment amounts were uncertain, for the year ended December 31, 2007 we recognized an estimated surcharge of $6.0 million including $1.7 million for the 2006 tax year and $4.3 million for the 2007 tax year. We intend to file our tax report for the 2007 tax year by October 15, 2008 and our tax report for the 2008 tax year by October 15, 2009. Each of these reports is subject to review by the OPUC and the OPUC is required to issue final orders on these tax reports by April 1 of the year following the respective filing, with rate adjustments effective as of the following June 1.

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 (see Part II, Item 8., Note 1, Industry Regulation, in the 2007 Form 10-K).

Three months ended June 30, 2008 compared to June 30, 2007:

Other revenues were $8.4 million in the second quarter of 2008, an increase of $0.3 million over the second quarter of 2007, with the increase primarily due to higher customer charges.

Six months ended June 30, 2008 compared to June 30, 2007:

Other revenues were $12.1 million in the first half of 2008, an increase of $1.0 million over the first half of 2007, with the increase primarily due to an increase in the interstate storage credit compared to 2007, offset in part by the collection in June 2008 of the regulatory adjustment for income taxes paid in 2006.

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Cost of Gas Sold

The total cost of gas sold was $124.0 million in the second quarter of 2008, an increase of $9.3 million or 8 percent compared to the second quarter of 2007. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use. The average cost of gas sold decreased from 85 cents per therm in the second quarter of 2007 to 76 cents in the second quarter of 2008. The 11 percent decrease in cost per therm of gas sold was primarily due to lower than embedded actual gas costs during 2007 which were included in our 8 to 10 percent PGA rate decrease effective November 1, 2007.

Our regulated utility does not generally earn a profit or incur a loss on the gas commodity. The OPUC and the WUTC require the natural gas commodity cost to be billed to customers at the same cost the utility incurs or is expected to incur such costs. However, under the PGA in Oregon, our net income is affected within defined limits by differences between actual and expected purchased gas costs (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2007 Form 10-K). In the first half of 2008, our actual gas costs were higher than the gas costs embedded in rates, while during the first half of 2007 our actual gas costs were significantly lower than the gas costs embedded in rates. The effect on shareholders was a margin gain of $10.6 million in the first half of 2007, compared to a margin loss of $5.8 million during the first half of 2008. In Washington, 100 percent of the actual gas costs are included in customer rates.

We use natural gas derivatives, primarily fixed-price commodity swaps, under the terms of our Financial Derivatives Policy to help manage our exposure to rising gas prices (see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2007 Form 10-K, and Note 10). In the second quarter of 2008, we realized net gains of $17.0 million from our financial hedges, compared to $2.5 million of net losses in the same period of 2007. In the first half of 2008, we realized net gains of $21.3 million from our financial hedges, compared to net losses of $10.0 million in the first half of 2007. Gains and losses from financial hedging of utility gas purchases generally are included in cost of gas and normally do not impact net income because the hedges are usually 100 percent passed through to customers in our annual PGA rate changes. However, to the extent that any utility gas hedge is entered into after the annual PGA filing, then the gains and losses are subject to our PGA incentive sharing mechanism with 67 percent deferred and 33 percent recorded to current income.

Business Segments Other than Utility Operations

Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility, asset optimization and our wholly-owned subsidiary, Gill Ranch. We earned $2.5 million and $4.9 million in net income from our gas storage business segment in the three and six months ended June 30, 2008, respectively, after regulatory sharing and income taxes, which is equivalent to 9 cents and 18 cents per share, respectively. This compares to net income of $2.7 million and $4.5 million, or 10 cents and 16 cents per share, in the three and six months ended June 30, 2007, respectively. The decrease in the three months ended June 30, 2008 was primarily due to higher depreciation and interest expense related to capital improvements and expansion at our Mist storage facility and costs related to Gill Ranch development, offset in part by higher revenues from storage services. The increase in the six month period was primarily due to an increase in firm storage services revenues and asset optimization with an independent energy marketing company (see Part II, Item 7., Results of Operations Business Segments Other Than Local Gas Distribution Gas Storage, in the 2007 Form 10-K).

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

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On May 1, 2008, a total of 100,000 therms per day of Mist storage capacity that had previously been available for interstate storage services was recalled and committed to use for core utility customers. This is the first recalled capacity since 2004. Under a regulatory agreement with the OPUC, non-utility gas storage at Mist, which has been developed in advance of core utility customer needs for interstate storage services, can be recalled to serve core utility customers. Storage capacity recalled by the core utility is added to utility rate base at net book value, and utility rates are adjusted with the next annual PGA filing so there is minimal regulatory lag in cost recovery.

Other

The other business segment consists of a wholly-owned subsidiary, Financial Corporation, our equity investment in Palomar (see Part II, Item 8., Note 2, Consolidated Subsidiary Operations and Segment Information, in the 2007 Form 10-K), and other non-utility investments.

Net income from the other business segment for the three and six months ended June 30, 2008 was $1.5 million and $1.8 million, respectively, compared to less than $0.1 million and $0.2 million for the three and six months ended June 30, 2007, respectively. The increase in net income in the three and six months ended June 30, 2008 is due to the sale of our investment in a Boeing 737-300 aircraft (see Note 2).

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the second quarter of 2008 were $25.8 million compared to $28.4 million in 2007, a decrease of $2.6 million or 9 percent. The decrease is largely due to lower 2008 incentive compensation accruals and additional savings from lower payroll expenses associated with process improvements (see Strategic Opportunities, above).

During the first six months of 2008, total operations and maintenance expenses were $54.3 million, down from $57.3 million in 2007, a decrease of $3.0 million or 5 percent. The major components of this change were a reduction in 2008 incentive compensation accruals and other payroll related expenses, partially offset by slightly higher costs associated with serving our growing customer base, additional legal expenses and higher facilities costs.

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, increased $1.4 million, or 26 percent, in the three months ended June 30, 2008 over the same period in 2007, and increased $1.7 million, or 13 percent, in the first half of 2008 compared to 2007. Regulatory fees increased $0.7 million in the second quarter of 2008 compared to the second quarter of 2007 and $0.5 million in the first half of 2008 compared to 2007. Property taxes increased $0.6 million in the second quarter of 2008 compared to the second quarter of 2007 and $0.9 million in the first half of 2008 compared to 2007 due to increased utility and non-utility plant in service and increased gas inventories.

We have been involved in litigation with the Oregon Department of Revenue (ODOR) over whether certain natural gas inventories and appliance inventories held for resale were improperly taxed as personal property. In November 2007, the Oregon Tax Court (Tax Court) ruled in our favor that these inventories were exempt from property tax. The ODOR subsequently filed a motion for reconsideration, which the Tax Court recently denied on July 19, 2008. The ODOR may appeal the judgment to the Oregon Supreme Court. If we are ultimately successful in this litigation, we would be entitled to a refund of approximately $3.0 million for property taxes paid on inventories beginning with the 2002/03 tax year, plus accrued interest. Due to the uncertainty of the proceeding, we have not recorded an adjustment to the financial statements to recognize any gain contingency.

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Depreciation and Amortization

Depreciation and amortization expense increased by $1.0 million, or 6 percent, and by $1.9 million, or 6 percent, in the three and six months ended June 30, 2008, respectively, compared to the same periods in 2007. The increased expense reflects ongoing capital expenditures for utility and non-utility plant that were made primarily to meet continuing customer growth, to upgrade utility operating facilities and to expand non-utility storage capacity.

In 2006, we completed a depreciation study on all company plant and equipment, which generally indicated that using the existing average service life depreciation method with new lives would result in a reduction in depreciation expense. In Oregon, we submitted the depreciation study for regulatory approval in 2007 and we expect to reach a settlement with the OPUC in 2008, with implementation of the new rates beginning in 2009. In Washington, the study and its recommended changes were submitted as part of the general rate case filed in March 2008, which we expect to be resolved by early 2009. We do not anticipate that the adoption of these new rates will have a material impact on our financial condition, results of operations or cash flow.

Other Income and Expense Net

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

Thousands	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Other income and expense - net:				
Gains from company-owned life insurance	$ 519	$ 425	$ 978	$ 905
Interest income	131	212	130	364
Other non-operating income (expense)	1,490	(915)	1,397	(1,189)
Net interest expense on deferred regulatory accounts	(176)	(479)	(343)	(221)
Gain (loss) from equity investments	(24)	276	(49)	198
Total other income and expense - net	$ 1,940	$ (481)	$ 2,113	$ 57

The $2.4 million increase in other income and expense net in the second quarter of 2008 compared to the same period in 2007 was primarily related to the sale of our investment in a Boeing 737-300 aircraft and to lower interest expense on deferred regulatory accounts during the second quarter of 2008. In the six months ended June 30, 2008, other income and expense net increased $2.1 million compared to the same period in 2007 primarily due to a the sale of our investment in the aircraft.

Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized increased $0.1 million, or 1 percent, in the three months ended June 30, 2008 compared to 2007, and remained the same for the six months ended June 30, 2008 compared to 2007.

Income Taxes

Income tax expense totaled $27.5 million in the six months ended June 30, 2008 compared to $29.9 million in the six months ended June 30, 2007. The effective tax rate was 37.2 percent in the first half of 2008 compared to 37.1 percent in the first half of 2007. The lower income tax expense in 2008 was primarily due to lower taxable income, which declined to $74.0 million from $80.6 million for the same period in 2007.

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Financial Condition

Capital Structure

Our goal is to maintain a target capital structure comprised 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 meet long-term debt redemption requirements and short-term commercial paper maturities (see Liquidity and Capital Resources, below). Achieving the target capital structure and maintaining sufficient liquidity are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at June 30, 2008 and 2007 and at December 31, 2007, including short-term debt, was as follows:

	June 30,		Dec. 31,
	2008	2007	2007
Common stock equity	51.6%	52.2%	47.4%
Long-term debt	42.4%	44.2%	40.8%
Short-term debt, including current maturities of long-term debt	6.0%	3.6%	11.8%
Total	100.0%	100.0%	100.0%

The common stock equity percentages in June 2008 and June 2007 were higher as compared to December 2007 primarily due to seasonal earnings and cash flows that increased common stock equity and reduced the combined long-term and short-term debt balances and percentages.

On April 24, 2008, the Board authorized an extension of our common stock share repurchase program through May 31, 2009, with an aggregate authorization of up to 2.8 million shares or $100 million. Purchases under this program are made on the open market or through privately negotiated transactions. No repurchases were made under this program in the first six months of 2008. As of June 30, 2008, total common stock repurchases under this program since inception in 2000 totaled 2.1 million shares or $83.3 million. See Financing Activities, and Part II, Item 2., Unregistered Sales of Equity Securities and Use of Proceeds, below.

Liquidity and Capital Resources

At June 30, 2008, we had $5.2 million of cash and cash equivalents compared to $4.9 million at June 30, 2007 and $6.1 million at December 31, 2007. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed lines of credit (see Credit Agreement, below). Proceeds from the issuance of long-term debt are used to finance capital expenditures and refinance maturing short-term or long-term debt.

Neither our Mortgage and Deed of Trust nor the indenture under which other long-term debt is issued contain credit rating triggers or stock price provisions that require the acceleration of debt repayment. Also, there are no credit rating triggers or stock price provisions contained in our contracts or other agreements with third parties, except for agreements with certain counterparties under our Financial Derivatives Policy. These agreements require the affected party to provide substitute collateral such as cash, guaranty or letter of credit if credit ratings are lowered to non-investment grade or, in some cases, if the mark-to-market value exceeds a certain threshold.

Based on the availability of short-term credit facilities and the ability to issue long-term debt and equity securities, we believe we have sufficient liquidity to satisfy our anticipated cash requirements, including the contractual obligations and investing and financing activities discussed below.

Off-Balance Sheet Arrangements

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

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Contractual Obligations

Since December 31, 2007, our future contractual obligations have increased $40 million, of which $22 million is in connection with an approved automated meter reading project, and $18 million is related to equipment purchases in connection with the development of Gill Ranch. Other than these two commitments, our future contractual obligations have not materially changed since December 31, 2007. Contractual obligations at December 31, 2007 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2007 Form 10-K.

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas purchases and accounts receivable, short-term debt is used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper is supported by a committed credit facility (see Credit Agreement, below, and Part II, Item 8., Note 6, in the 2007 Form 10-K). We had $67.7 million in commercial paper notes outstanding at June 30, 2008, compared to $42.1 million outstanding at June 30, 2007 and $143.1 million outstanding at December 31, 2007. Commercial paper balances are typically lower at the end of the first and second quarters compared to year-end due to receivable collections from higher winter sales and the withdrawal of gas inventories from storage during the winter heating season. This year s outstanding balances were higher than last year primarily due to the higher gas costs and the corresponding increase in regulatory PGA deferrals discussed above in Results of Operations Comparison of Utility Operations Cost of Gas Sold.

Credit Agreement

We have a credit agreement for unsecured revolving loans totaling $250 million available and committed for a term expiring on May 31, 2012. Pursuant to the terms of the credit agreement, it may be extended for additional one-year periods subject to lender approval. Six of seven lenders under the credit agreement, with commitments totaling $210 million, agreed to extend their obligations for an additional one-year period, to May 31, 2013. The credit agreement also allows us to request increases in the total commitment amount, up to a maximum amount of $400 million through May 31, 2012, and to replace any lenders who decline to extend the terms of the credit agreement. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. All principal and unpaid interest with one lender, totaling $40 million, is due and payable on May 31, 2012. The remaining six lenders with commitments totaling $210 million, subject to extensions if any, are payable and due on May 31, 2013. There were no outstanding balances under this credit agreement at June 30, 2008 and 2007 or December 31, 2007. The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at June 30, 2008 and 2007 and December 31, 2007. For additional information regarding our credit agreement, see Part II, Item 7., Financial Condition Credit Agreement, in the 2007 Form 10-K.

Credit Ratings

The table below summarizes our debt credit ratings from Standard and Poor s Rating Services (S&P) and Moody s Investors Service (Moody s).

	S&P	Moody s
Commercial paper (short-term debt)	A-1+	P-1
Senior secured (long-term debt)	AA-	A2
Senior unsecured (long-term debt)	A+	A3
Ratings outlook	Stable	Positive

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Both rating agencies have assigned NW Natural an investment grade rating. These credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

Redemptions of long-term debt during the six months ended June 30, 2008 and 2007 and the year-ended December 31, 2007 were as follows:

Thousands	Six months ended June 30, 2008	Six months ended June 30, 2007	Year ended Dec. 31, 2007
Medium-Term Notes			
6.31% Series B due 2007	$	$ 20,000	$ 20,000
6.80% Series B due 2007		9,500	9,500
	$	$ 29,500	$ 29,500

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, gas prices, deferred income taxes, changes in working capital requirements, regulatory deferrals and other cash and non-cash adjustments to operating results. The overall change in cash flow from operating activities for the six months ended June 30, 2008 compared to the same period in 2007 was a decrease of $42.2 million. The major factors contributing to the cash flow changes in the first six months of 2008 compared to the first six months of 2007 were as follows:

- a decrease in net income of $4.2 million;
- a decrease in deferred gas costs of $47.3 million, primarily related to the refunding of prior year s gas cost savings and the accumulation of current year s cost deferrals from higher gas prices compared to our weighted-average cost of gas;
- a decrease of $21.3 million resulting from a smaller decrease in accounts receivable and accrued unbilled revenue due to lower balances at year end 2007 compared to in the prior year;
- an increase of $20.8 million resulting from a larger decrease in gas inventories due to increased withdrawals in 2008 compared to 2007;
- an increase of $16.1 million resulting from an increase in deferred tax balances due to accelerated tax deductions from bonus depreciation; and
- an increase of $1.9 million from higher depreciation expense.

Investing Activities

Cash requirements for investing activities in the first six months of 2008 totaled $46.7 million, down from $52.5 million in the same period of 2007. Investments in utility plant totaled $41.3 million in the first six months of 2008, compared to the $40.8 million expended in the same period of 2007.

Investments in non-utility property during the first six months of 2008 totaled $5.1 million, down from $14.4 million during the first six months of 2007. In 2007 we invested in capital improvements and expansion at our Mist gas storage facilities.

Cash used in other investing activities during the first six months of 2008 totaled $0.2 million, down from an increase in cash of $2.7 million during the first six months of 2007. The increase in 2007 was primarily due to $2.7 million of proceeds received from our aircraft leveraged lease investment. The decrease in 2008 is primarily due to $6.8 million of proceeds received from the sale of our investment in a Boeing 737-300 aircraft, offset by a $3.0 million investment in the Palomar project and a $4.3 million restricted cash investment for Gill Ranch.

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Our utility capital expenditures are expected to total about $105 million in 2008, including amounts for a new automated meter reading project. In addition, we expect to spend approximately $15 to $20 million for non-utility capital expenditures for the Gill Ranch and Palomar projects in 2008. The planning and permitting phase of the Palomar project is expected to continue through 2009 and cost approximately $45 million, 50 percent of which would be contributed by us.

Financing Activities

Cash used in financing activities in the first six months of 2008 totaled $92.3 million, down from $128.7 million in the same period of 2007. Short-term debt balances decreased by $75.4 million in the first six months of 2008 compared to a decrease of $58.0 million in 2007. Under our common stock repurchase program, no shares were purchased in 2008 compared to 509,500 shares purchased at a total cost of $23.2 million in the first six months of 2007. No long-term debt was issued or redeemed in the first six months of 2008, while $29.5 million was redeemed in the first six months of 2007.

Pension Funding Status

Our policy is to fund the qualified defined benefit pension plans, as needed, based on tax regulations and funding requirements under federal law, including funding the amounts required by the Employee Retirement Income Security Act of 1974. In addition, it is our intent to contribute sufficient amounts as needed on an actuarial basis to maintain funding targets and to provide for the timely payment of future benefits under these plans. Our qualified defined benefit pension plans were funded at nearly 100 percent of the projected benefit obligation at December 31, 2007. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Part II, Item 7., Pension Cost and Funding Status of Qualified Retirement Plans, and Part II, Item 8., Note 7, Pension and Other Postretirement Benefits, in the 2007 Form 10-K.

Ratios of Earnings to Fixed Charges

For the three, six and twelve months ended June 30, 2008 our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 1.53, 4.78 and 3.77, respectively. For the three, six, and twelve months ended June 30, 2007 our ratios of earnings to fixed charges were 1.41, 5.07 and 3.69, respectively. For the twelve months ended December 31, 2007, our ratio of earnings to fixed charges was 3.92. For this purpose, earnings consist of net income before taxes plus fixed charges. Fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. Because a significant part of our business is of a seasonal nature, the ratios for the interim periods are not necessarily indicative of the results for a full year.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of loss is reasonably estimable in accordance with SFAS No. 5, Accounting for Contingencies (see Part II, Item 7., Application of Critical Accounting Policies and Estimates, in the 2007 Form 10-K). At June 30, 2008, we had a regulatory asset relating to environmental accruals of $64.2 million, which includes $27.5 million of total paid expenditures to date, $32.1 million for additional environmental costs expected to be paid in the future and accrued interest of $4.6 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.

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Forward-Looking Statements

This report and other presentations made by us from time to time may contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and other statements that are other than statements of historical facts. Our expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis. However, each forward-looking statement involves uncertainties and is qualified in its entirety by reference to the following important factors, among others, that could cause our actual results to differ materially from those projected, including:

- prevailing state and federal governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in tax laws and policies, changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity;

- market conditions and pricing of natural gas relative to other energy sources;

- application of the OPUC rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;

- weather conditions, pandemic events and other natural phenomena, including earthquakes or other geohazard events;

- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;

- competition for retail and wholesale customers;

- the creditworthiness of customers, suppliers and financial derivative counterparties;

- our dependence on a single pipeline transportation provider for natural gas supply;

- property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;

- financial and operational risks relating to business development and investment activities, including Palomar and the proposed Gill Ranch storage facility;

- unanticipated changes that may affect our liquidity or access to capital markets;

our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;

unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;

economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;

unanticipated changes in operating expenses and capital expenditures;

changes in estimates of potential liabilities relating to environmental contingencies;

unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;

capital market conditions, including their effect on financing costs, the fair value of pension assets and on pension and other postretirement benefit costs;

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- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and

- legal and administrative proceedings and settlements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural, also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for us to predict all such factors, nor can we assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price risk, interest rate risk, foreign currency risk, credit risk and weather risk (see Part II, Item 7A. in the 2007 Form 10-K, and Part II, Item 1A., Risk Factors, below). 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, subject to a regulatory prudence review. At June 30, 2008 and 2007, notional amounts under these financial hedge contracts totaled $332.6 million and $269.2 million, respectively. If all of the commodity-based financial hedge contracts had been settled on June 30, 2008, a gain of about $62.3 million would have been realized and recorded to a deferred regulatory account (see Note 10). We monitor the liquidity of our financial hedge contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our financial hedge contracts settle by October 31, 2010. The $62.3 million unrealized gain is an estimate of future cash flows based on forward market prices that are expected to be received as follows: $53.3 million in the next 12 month contract period and $9.0 million between the next 12 and 24 month contract period. The amount realized will change based on market prices at the time contract settlements are fixed.

In recent months, natural gas commodity prices were higher than prices embedded in our current PGA for unhedged purchases. To the extent that we purchase gas above the prices embedded in rates for current customer consumption (i.e. not for storage injections), our earnings are negatively impacted because 33 percent of any difference between the actual purchase gas costs and the embedded gas costs in rates to Oregon customers are recognized in current income. In the second quarter of 2008, gas prices rose sharply to levels above the prices embedded in rates, and we recognized a loss of $5.5 million due to those higher prices. Although spot prices for gas supplies from Alberta, Canada and the U.S. Rockies have recently declined and the current forward price for purchases from now until the end of our current PGA is lower than the prices we paid for unhedged purchases in the second quarter of 2008, we could continue to incur additional expense under the current PGA sharing mechanism if gas costs remain at levels higher than the embedded PGA prices. We expect the PGA sharing mechanism to be modified effective November 1, 2008 (see Part II, Issues, Challenges and Performance Measures, above).

Credit Risk

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity hedge contracts was $60.8 million at June 30, 2008. Our Financial Derivatives Policy requires counterparties to have a minimum 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. Some counterparties were recently downgraded but continue to maintain investment grade ratings (see table below). Due to current market conditions and credit concerns, we have tightened our credit requirements and are entering into new derivative transactions only with AA/Aa category or higher rated counterparties.

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The following table summarizes our credit exposure, based on estimated fair value, and the corresponding counterparty 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:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)		
Thousands	June 30, 2008	June 30, 2007	Dec. 31, 2007
AAA/Aaa	$ 8,906	$ (4,486)	$ (309)
AA/Aa	45,863	(12,559)	(13,941)
A/A	6,013		123
BBB/Baa			
Total	$ 60,782	$ (17,045)	$ (14,127)

Credit Exposure to Customers and Increased Short-term Indebtedness. Future increases in the price of gas may cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be materially in advance of when these costs are recovered through the collection of customer bills for gas delivered. Significant increases in the price of gas sold can also slow our collection efforts as customers experience increased difficulty in paying their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater expense associated with collection efforts and increased bad debt expense.

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of June 30, 2008, the principal executive officer and principal financial officer of Northwest Natural Gas Company (NW Natural) have evaluated 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 Exchange Act). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by us and included in our reports filed with the Securities and Exchange Commission (Commission) under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Commission s rules and forms and are also effective to ensure that information required to be disclosed by us and included in our reports filed with or furnished to the Commission under the Exchange Act is accumulated and communicated to our management 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).

In the first half of 2008 we implemented an integrated information system for the general ledger, accounts payable, miscellaneous accounts receivable, inventory management and purchasing functions. The new system interfaces with our existing customer information system, payroll, fixed assets and construction work management systems. The integrated information system is designed to:

- automate controls with auditable financial and operational workflow processes;
- automate integration of multiple systems with data entered only once into the system; and

automate more of the monthly closing process.

Other than as described above, there has been no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

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

Item 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2007. 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 2007 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 adversely 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, 2008 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [2]
Balance forward			2,124,528	$ 16,732,648
04/01/08 - 04/30/08	1,713	$ 44.39		
05/01/08 - 05/31/08	23,473	$ 44.56		
06/01/08 - 06/30/08	1,514	$ 46.22		
Total	26,700	$ 44.65	2,124,528	$ 16,732,648

(1) During the quarter ended June 30, 2008, 23,227 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, 3,473 shares of our common stock were purchased on the open market during the quarter under equity-based programs. During the three months ended June 30, 2008, 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 Board approved share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. On April 24, 2008, the Board extended our share repurchase program through May 31, 2009 and confirmed its previous authorization to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the six months ended June 30, 2008, no shares of our common stock were purchased pursuant to this program. Since the program s inception in 2000 we have repurchased 2.1 million shares of common stock at a total cost of $83.3 million.

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

NW Natural s Annual Meeting of Shareholders was held in Portland, Oregon on May 22, 2008. At the meeting, five director-nominees were elected, as follows:

Director	Class	Term Expiring	Votes For	Votes Withheld
Martha L. Byorum	III	2011	22,644,176	448,099
John D. Carter	III	2011	22,605,149	487,126
C. Scott Gibson	III	2011	21,129,205	1,963,071
Jane L. Peverett	II	2010	22,703,783	388,493
George J. Puentes	I	2009	22,346,362	745,913

The other six directors whose terms of office as directors continued after the Annual Meeting are: Timothy P. Boyle, Mark S. Dodson, Tod R. Hamachek, Randall C. Papé, Kenneth Thrasher and Russell F. Tromley.

The following matters also were acted upon at the meeting:

The Company s Employee Stock Purchase Plan was amended by the following vote:

For	Against	Abstain	Broker Non-Vote
17,177,134	404,016	383,442	5,127,683

The increase in the number of shares of common stock authorized under Article III of the Company s Restated Articles of Incorporation was approved by the following vote:

For	Against	Abstain
20,395,743	2,177,429	519,102

The ratification of the Audit Committee s appointment of PricewaterhouseCoopers LLP as the Company s independent registered public accounting firm for the year 2008 was approved by the following vote:

For	Against	Abstain
22,643,457	294,802	154,014

No other matters were acted upon at the meeting.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

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SIGNATURE

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

	NORTHWEST NATURAL GAS COMPANY (Registrant)
Dated: August 6, 2008	/s/ Stephen P. Feltz Stephen P. Feltz Principal Accounting Officer, Treasurer and Controller

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

June 30, 2008

Document	**Exhibit Number**
Northwest Natural Gas Company Restated Articles of Incorporation as filed and effective June 3, 2008	3.1
Computation of Ratio of Earnings to Fixed Charges	12
Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.1
Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.2
Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1