NORTHWEST NATURAL GAS CO
Form 10-Q
August 07, 2007
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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, 2007

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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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, 2007, 26,580,275 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, 2007

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

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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, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Operating revenues:				
Gross operating revenues	$ 183,249	$ 170,979	$ 577,340	$ 561,370
Less: Cost of sales	114,744	105,036	360,213	360,435
Revenue taxes	4,387	4,196	14,001	13,724
Net operating revenues	64,118	61,747	203,126	187,211
Operating expenses:				
Operations and maintenance	28,420	27,909	57,259	56,156
General taxes	5,351	6,066	13,168	13,639
Depreciation and amortization	16,972	15,962	33,757	31,792
Total operating expenses	50,743	49,937	104,184	101,587
Income from operations	13,375	11,810	98,942	85,624
Other income and expense - net	(481)	410	57	928
Interest charges - net of amounts capitalized	8,801	9,184	18,368	19,039
Income before income taxes	4,093	3,036	80,631	67,513
Income tax expense	1,476	1,042	29,939	24,486
Net income	$ 2,617	$ 1,994	$ 50,692	$ 43,027
Average common shares outstanding:				
Basic	26,999	27,563	27,114	27,574
Diluted	27,164	27,611	27,261	27,621
Earnings per share of common stock:				
Basic	$ 0.10	$ 0.07	$ 1.87	$ 1.56
Diluted	$ 0.10	$ 0.07	$ 1.86	$ 1.56

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	**June 30, 2007 (Unaudited)**	**June 30, 2006 (Unaudited)**	**Dec. 31, 2006**
Assets:			
Plant and property:			
Utility plant	$ 2,002,460	$ 1,914,301	$ 1,963,498
Less accumulated depreciation	595,195	557,632	574,093
Utility plant - net	1,407,265	1,356,669	1,389,405
Non-utility property	57,061	41,094	42,652
Less accumulated depreciation and amortization	7,392	6,452	6,916
Non-utility property - net	49,669	34,642	35,736
Total plant and property	1,456,934	1,391,311	1,425,141
Current assets:			
Cash and cash equivalents	4,899	6,636	5,767
Accounts receivable	45,656	44,782	82,070
Accrued unbilled revenue	18,434	16,657	87,548
Allowance for uncollectible accounts	(2,975)	(3,814)	(3,033)
Regulatory assets	18,871	25,692	31,509
Fair value of non-trading derivatives	4,538	15,967	5,109
Inventories:			
Gas	52,615	76,667	68,576
Materials and supplies	9,245	9,546	9,552
Prepayments and other current assets	10,186	47,648	21,695
Total current assets	161,469	239,781	308,793
Investments, deferred charges and other assets:			
Regulatory assets	190,145	103,851	164,771
Fair value of non-trading derivatives	1,388	9,598	1,448
Other investments	48,950	54,962	47,985
Other	9,015	9,448	8,718
Total investments, deferred charges and other assets	249,498	177,859	222,922
Total assets	$ 1,867,901	$ 1,808,951	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	June 30, 2007 (Unaudited)	June 30, 2006 (Unaudited)	Dec. 31, 2006
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 350,360	$ 383,103	$ 371,127
Earnings invested in the business	262,209	229,684	230,774
Accumulated other comprehensive income (loss)	(2,292)	(1,911)	(2,356)
Total common stock equity	610,277	610,876	599,545
Long-term debt	517,000	492,000	517,000
Total capitalization	1,127,277	1,102,876	1,116,545
Current liabilities:			
Notes payable	42,100	55,800	100,100
Long-term debt due within one year		29,500	29,500
Accounts payable	66,254	76,804	113,579
Taxes accrued	16,101	13,886	21,230
Interest accrued	2,820	2,878	2,924
Regulatory liabilities	42,473	21,711	11,919
Fair value of non-trading derivatives	18,115	18,311	38,772
Other current and accrued liabilities	25,858	17,299	21,455
Total current liabilities	213,721	236,189	339,479
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	208,978	224,861	210,084
Regulatory liabilities	205,838	189,983	202,982
Pension and other postretirement benefit liabilities	55,533	17,946	52,690
Fair value of non-trading derivatives	6,585	7,726	11,031
Other	49,969	29,370	24,045
Total deferred credits and other liabilities	526,903	469,886	500,832
Commitments and contingencies (see Note 11)			
Total capitalization and liabilities	$ 1,867,901	$ 1,808,951	$ 1,956,856

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, 2007	2006
Operating activities:		
Net income	$ 50,692	$ 43,027
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	33,757	31,792
Deferred income taxes and investment tax credits	(2,051)	(3,453)
Undistributed earnings from equity investments	(198)	(59)
Deferred gas savings (costs) - net	20,461	(1,620)
Non-cash expenses related to qualified defined benefit pension plans	2,108	2,883
Deferred environmental costs	(4,069)	(3,586)
Income from life insurance investments	(905)	(1,797)
Other	(1,832)	5,787
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	105,548	105,238
Inventories of gas, materials and supplies	16,268	(52)
Income taxes receivable		13,234
Prepayments and other current assets	8,855	5,739
Accounts payable	(47,636)	(58,483)
Accrued interest and taxes	(5,233)	1,121
Other current and accrued liabilities	4,528	(5,084)
Cash provided by operating activities	180,293	134,687
Investing activities:		
Investment in utility plant	(40,845)	(41,186)
Investment in non-utility property	(14,378)	(236)
Proceeds from life insurance	56	892
Other	2,658	2,953
Cash used in investing activities	(52,509)	(37,577)
Financing activities:		
Common stock issued, net of expenses	1,389	1,556
Common stock repurchased	(23,631)	(1,608)
Long-term debt retired	(29,500)	(8,000)
Change in short-term debt	(58,000)	(70,900)
Cash dividend payments on common stock	(19,257)	(19,030)
Other	347	365
Cash used in financing activities	(128,652)	(97,617)
Increase (decrease) in cash and cash equivalents	(868)	(507)
Cash and cash equivalents - beginning of period	5,767	7,143

Cash and cash equivalents - end of period	$ 4,899	$ 6,636
Supplemental disclosure of cash flow information:		
Interest paid	$ 18,652	$ 19,052
Income taxes paid	$ 33,000	$ 9,520

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

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), consisting of our regulated gas distribution business and our regulated gas storage business, and our non-regulated wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation).

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 2006 Annual Report on Form 10-K (2006 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.

Certain prior year balances on our consolidated balance sheets and statements of cash flows have been reclassified to conform with the current presentation. The financial statement classification was changed to reflect the current portion of regulatory assets and liabilities, which was previously included in a separate regulatory section on the balance sheet, and the current portion of fair value of non-trading derivative assets and liabilities, which was included under other assets or other liabilities. 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.

2. New Accounting Standards

Adopted Standards

Accounting for Uncertainty in Income Taxes. On January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109, which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, we recognized no change in our recorded assets or liabilities for unrecognized income tax benefits. Based on our analysis of all material tax positions taken, management believes the technical merits of these positions are justified and expects that the full amount of the deductions taken and associated tax benefits will be allowed.

FIN 48 requires the evaluation of a tax position as a two-step process. We must determine whether it is more likely than not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the more likely than not recognition threshold, then the tax benefit is measured and recorded at the largest amount that is greater than 50 percent likely of being realized upon effective settlement. The re-assessment of our tax positions in accordance with FIN 48 did not result in any material change to our financial condition, results of operations or cash flows. For additional information regarding income taxes, see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Income Taxes, and Part II, Item 8., Note 8, in the 2006 Form 10-K.

We are subject to U.S. federal income taxes as well as several state and local income taxes. All of our U.S. federal income tax matters audited by the Internal Revenue Service through the 2004 tax year were concluded during 2006 with no material adjustments. Also, substantially all material state and local income tax matters are closed for the years through the 2002 tax year.

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Based upon our assessment in connection with the adoption of FIN 48, we do not believe there are any tax positions taken that would not be fully sustained upon audit.

We have also assessed the classification of interest and penalties, if any, related to income tax matters. Pursuant to the application of FIN 48, we have made an accounting election to treat interest and penalties related to income tax matters, if any, as a component of income tax expense rather than other operating expenses.

Accounting for Certain Hybrid Instruments. In February 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 155, Accounting for Certain Hybrid Instruments, which amended SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125. SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for as a whole if the holder elects to account for the whole instrument on a fair value basis. SFAS No. 155 is effective for all financial instruments acquired or issued after January 1, 2007. The adoption and implementation of SFAS No. 155 did not have an impact on our financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which provides a common definition for the measurement of fair value for use in applying generally accepted accounting principles in the United States of America and in preparing financial statement disclosures. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 157, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

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 are evaluating the effect of the adoption and implementation of SFAS No. 159, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

Offsetting of Amounts Related to Certain Contracts. In April 2007, FASB issued FASB Staff Position (FSP) FIN 39-1 which amends FIN 39, Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105. It applies to entities entering into master netting arrangements as part of derivative transactions by allowing net derivative positions to be offset in financial statements against the fair value of amounts recognized for the right to reclaim cash collateral or return cash collateral. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the effect of the adoption and implementation of FSP FIN 39-1, which is not expected to have a material impact on our financial condition and is expected to have no impact on our results of operations or cash flows.

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3. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Net income	$ 2,617	$ 1,994	$ 50,692	$ 43,027
Average common shares outstanding - basic	26,999	27,563	27,114	27,574
Additional shares for stock-based compensation plans	165	48	147	47
Average common shares outstanding - diluted	27,164	27,611	27,261	27,621
Earnings per share of common stock - basic	$ 0.10	$ 0.07	$ 1.87	$ 1.56
Earnings per share of common stock - diluted	$ 0.10	$ 0.07	$ 1.86	$ 1.56

For the three- and six- month periods ended June 30, 2007 and the three-month period ended June 30, 2006, no common shares were excluded from the calculation of diluted earnings per share because the effect of all shares was dilutive. For the six-month period ended June 30, 2006, 600 common shares were excluded from the calculation of diluted earnings per share because the shares would not have a dilutive effect.

4. Capital Stock

At June 30, 2007, we had 60,000,000 common shares authorized and 26,815,203 common shares outstanding.

We have in place a repurchase program for our common stock, which was originally approved by the Board in May 2000. During the six months ended June 30, 2007, 509,500 shares of our common stock were repurchased for $23.2 million, pursuant to this program. In April 2007, the Board extended the program through May 31, 2008, further increased the authorization from 2.6 million shares to 2.8 million shares and further increased the dollar limit from $85 million to $100 million. At June 30, 2007, we had 1,129,400 shares, or up to $37.7 million, that remain authorized under the program.

5. 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, see Part II, Item 8., Note 4, in the 2006 Form 10-K and current updates provided below.

In November 2005, the FASB issued FSP No. SFAS 123(R)-3 (FSP 123(R)), Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards. FSP 123(R) provides an elective alternative transition method for calculating the pool of excess tax benefits available to absorb tax deficiencies recognized subsequent to the adoption of FAS 123(R). Companies may take up to one year from the effective date of FSP 123(R) to evaluate

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the available transition alternatives and make a one-time election as to which method to adopt. We have adopted the long-form method for calculating the pool of excess tax benefits.

Long-Term Incentive Plan. During the six months ended June 30, 2007, 42,000 performance-based share awards, at target levels, were granted under the LTIP, with a weighted-average grant date fair value of $33.29 per share.

Restated Stock Option Plan. In February 2007, we granted options on a total of 100,600 shares of common stock under the Restated SOP, with an exercise price equal to the closing market price of our common stock on the date of grant. The options vest over the four-year period following date of grant and have a term of 10 years and 7 days. The fair value, estimated at the date of grant using the Black-Scholes option pricing model, was based on the following weighted-average assumptions:

Risk-free interest rate	4.7%
Expected life (in years)	6.2
Expected market price volatility factor	17.2%
Expected dividend yield	3.2%
Forfeiture rate	4.36%

As of June 30, 2007, 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 2010.

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6. Long-Term Debt

At June 30, 2007 and 2006 and December 31, 2006, we had outstanding long-term debt as follows:

Thousands	June 30, 2007 (Unaudited)	June 30, 2006 (Unaudited)	Dec. 31, 2006
Medium-Term Notes			
First Mortgage Bonds:			
6.31 % Series B due 2007[1]	$	$ 20,000	$ 20,000
6.80 % Series B due 2007[2]		9,500	9,500
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
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	521,500	546,500
Less long-term debt due within one year		29,500	29,500
Total long-term debt	$ 517,000	$ 492,000	$ 517,000

(1) Redeemed at maturity in March 2007.

(2) Redeemed at maturity in May 2007.

7. Notes Payable and Syndicated Line of Credit

In May 2007, we entered into a credit agreement for unsecured revolving loans totaling $250 million with seven lenders under a syndicated facility (credit facility), replacing the prior $200 million bilateral credit agreements which were terminated. The credit facility allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit facility also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. The credit facility is available and committed for a term of five

years expiring on May 31, 2012, which may be extended for additional one-year periods, subject to lender approval. The credit facility continues to be used primarily as back-up credit support for the notes payable issued under our commercial paper program. Commercial paper borrowing provides the liquidity to meet our working capital and interim financing requirements. Under the terms of the credit facility, we pay upfront fees, annual commitment fees and administrative agent fees, but we are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under the credit facility are based on our long-term unsecured debt ratings and on then-current market interest rates. All principal and unpaid interest under the credit facility is due and payable on May 31, 2012, subject to extensions, if any. We had no amounts outstanding under our credit facility at June 30, 2007.

The credit facility requires that we maintain credit ratings with Standard & Poor s and Moody s Investors Service, Inc. and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the bank lines. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit facility 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 to accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at June 30, 2007. Our prior credit facilities required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at June 30, 2006 and December 31, 2006.

8. 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 Derivative Instruments and Hedging Activities, 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 (see Part II, Item 8., Note 11, in the 2006 Form 10-K).

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At June 30, 2007 and 2006 and at December 31, 2006, unrealized gains and losses from mark-to-market valuations of our derivative instruments were primarily recorded as regulatory liabilities or regulatory assets, respectively, because the net realized gains and losses at settlement are included in utility gas costs, and subject to our regulatory Purchased Gas Adjustment (PGA) deferral mechanism. The estimated fair value of unrealized gains and losses on derivative instruments outstanding, as determined using a discounted cash flow model for swaps and indexed-price contracts, and a Black-Scholes option pricing model for options, was as follows:

	June 30, 2007		June 30, 2006		Dec. 31, 2006	
Thousands	**Current**	**Non-Current**	**Current**	**Non-Current**	**Current**	**Non-Current**
Fair Value Gain (Loss):						
Natural gas commodity-based derivative instruments:						
Fixed-price financial swaps	$ (12,721)	$ (1,301)	$ (2,026)	$ 3,879	$ (33,965)	$ (6,312)
Fixed-price financial options		(3,023)			(678)	
Indexed-price physical supply	(1,119)	(873)	(229)	(2,342)	1,115	(3,271)
Fixed-price physical supply			(286)			
Physical options				335		
Foreign currency forward purchases	263		197		(135)	
Total	$ (13,577)	$ (5,197)	$ (2,344)	$ 1,872	$ (33,663)	$ (9,583)

In the second quarter of 2007, we realized net losses of $2.5 million from the settlement of fixed-price financial derivative contracts, which were recorded as increases to the cost of gas, compared to net losses of $10.5 million in the same period of 2006. We realized net losses of $10.0 million from these settlements in the six months ended June 30, 2007, compared to net gains of $7.0 million in the same period of 2006. Realized losses in the first three and six months of 2007 from financial derivative contracts were more than offset by lower gas purchase costs from the underlying floating rate physical supply contracts. The foreign currency gains and losses are also included in cost of gas at settlement as they relate to purchases of gas from Canadian suppliers.

As of June 30, 2007, all non-current natural gas financial derivative contracts mature on or before October 31, 2008, a portion of which may be extended through October 31, 2009.

9. Segment Information

Our core business is the local gas distribution segment, also referred to as the utility, which involves the distribution and sale of natural gas to customers in Oregon and Washington. Another business segment, gas storage, represents natural gas storage services provided to intrastate and interstate customers and includes asset optimization services under a contract with an independent energy marketing company. The remaining business segment, other, primarily consists of non-regulated investments in alternative energy projects in California, a Boeing 737-300 aircraft leased to Continental Airlines and two low-income housing buildings in Portland, Oregon. Our net investment in the aircraft was reclassified to current assets as of December 31, 2006, with the original lease term expiring in September 2007.

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

Thousands	Utility	Gas Storage	Other	Total
	Three Months Ended June 30,			
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
Income from financial investments	425		276	701
Net income (loss)	(79)	2,663	33	2,617
2006				
Net operating revenues	$ 58,047	$ 3,671	$ 29	$ 61,747
Depreciation and amortization	15,742	220		15,962
Income (loss) from operations	8,992	3,249	(431)	11,810
Income from financial investments	414		109	523
Net income (loss)	214	1,817	(37)	1,994

Thousands	Utility	Gas Storage	Other	Total
	Six Months Ended June 30,			
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
Income from financial investments	905		198	1,103
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
2006				
Net operating revenues	$ 180,391	$ 6,750	$ 70	$ 187,211
Depreciation and amortization	31,352	440		31,792
Income (loss) from operations	80,114	5,933	(423)	85,624
Income from financial investments	1,797		59	1,856
Net income	39,677	3,266	84	43,027
Total assets at June 30, 2006	$ 1,761,230	$ 36,084	$ 11,637	$ 1,808,951

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10. Pension and Other Postretirement Benefits

The following table provides the components of net periodic benefit cost for our qualified and non-qualified defined benefit pension plans and other postretirement benefit plans:

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	**2007**	**2006**	**2007**	**2006**
Service cost	$ 2,159	$ 1,961	$ 147	$ 138
Interest cost	3,992	3,758	320	283
Expected return on plan assets	(4,636)	(4,404)		
Amortization of loss	538	917	1	
Amortization of prior service cost	246	245	50	49
Amortization of transition obligation			103	103
Net periodic benefit cost	2,299	2,477	621	573
Amount allocated to construction	(533)	(701)	(210)	(187)
Net amount charged to expense	$ 1,766	$ 1,776	$ 411	$ 386

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	**2007**	**2006**	**2007**	**2006**
Service cost	$ 4,318	$ 3,922	$ 295	$ 275
Interest cost	7,987	7,516	640	566
Expected return on plan assets	(9,272)	(8,807)		
Amortization of loss	1,077	1,833	2	
Amortization of prior service cost	491	490	99	98
Amortization of transition obligation			206	206
Net periodic benefit cost	4,601	4,954	1,242	1,145
Amount allocated to construction	(1,048)	(1,401)	(412)	(374)
Net amount charged to expense	$ 3,553	$ 3,553	$ 830	$ 771

See Part II, Item 8., Note 7, in the 2006 Form 10-K for more information about our pension and other postretirement benefit plans.

Employer Contributions

During the six months ended June 30, 2007, we did not make and were not required to make cash contributions to our qualified non-contributory defined benefit plans, but cash contributions in the form of ongoing benefit payments of $1.1 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 2006 Form 10-K for a discussion of future payments.

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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 for certain sites 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. Costs actually incurred over time could significantly exceed the amounts of liability accrued to date, and revised estimates of future expenditures could result in material changes from time to time in the amounts of accrued liabilities. See Part II, Item 8., Note 12, in the 2006 Form 10-K.

During the second quarter of 2007, we accrued an additional $28.8 million for estimated environmental liabilities based upon new information and analysis developed by management with the assistance of outside counsel and consultants. Of the $28.8 million, $23.1 million represents the present value of estimated future expenditures of $29.2 million which have been projected over a period of two to eight years, using an average discount rate of 5.6 percent based on estimated long term borrowing rates for comparable periods. In years two through five, we expect payments to be $14.2 million, less than $0.1 million, $5.0 million and less than $0.1 million, respectively, with the remaining $10 million in year eight. Over the next twelve months, we expect payments to total $6.6 million. The status of each site currently under investigation and expected recovery of such costs are provided below.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality s (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised upland remediation investigation report and submitted it to the ODEQ for review. In the second quarter of 2007, the estimated liability for this site increased by $16.4 million based on updated information for the development of proposed studies of in-water source control and completion of the recommended remediation actions. We have accrued a total liability of $21.8 million at June 30, 2007 for the Gasco site, which includes $15.1 million on a present value basis, as well as $6.7 million, 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 is now 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 portion of this site. In the second quarter of 2007, the estimated liability for this site increased by $0.8 million related to future expenditures in connection with the study, which is at the low end of the range of potential additional 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 site and the Siltronic site. 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,

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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. In the second quarter of 2007, we received a revised estimate and based upon that review, we accrued an additional liability of $9.9 million for additional expenditures related to RI/FS development and environmental remediation and monitoring after the RI/FS work plan is completed.

In October 2005, we completed the removal of a tar deposit in the Portland Harbor, which was approved by the EPA. The total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $10.4 million. To date, we have paid $9.5 million on work related to the removal of the tar deposit.

As of June 30, 2007, we have accrued a total liability of $11.7 million, including $8.0 million determined on a present value basis and $3.7 million related to the remainder of the Portland Harbor site, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

Central Gas Storage Tanks. In September 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, or as a result of historic gas handling practices. In early 2007, we received notice that this site has been 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. In the second quarter of 2007, we accrued $0.5 million for estimated liabilities related to the design of an investigational plan for this site in cooperation with the ODEQ. We cannot estimate a further range of liability until studies are complete.

Front Street site. The Front Street site was the former location of a gas manufacturing plant operated by our predecessor between 1860 and 1913. During the second quarter of 2007, we accrued $1.2 million for a focused source control investigation of this site, based on recent information that indicates that a source control investigation is likely. Current information is not sufficient to reasonably estimate additional liabilities, if any, or the range of potential liabilities. We cannot estimate a further range of liability until studies are complete.

The following table summarizes the accrued liabilities relating to environmental sites at June 30, 2007 and 2006 and December 31, 2006:

	Current Liabilities			**Non-Current Liabilities**		
	June 30,		**Dec. 31,**	**June 30,**		**Dec. 31,**
Thousands	**2007**	**2006**	**2006**	**2007**	**2006**	**2006**
Gasco site	$ 3,775	$	$	$ 17,988	$ 2,610	$ 6,634
Siltronic site	810				1,706	74
Portland Harbor site	1,507			10,160	1,602	3,158
Central Gas Storage Tanks site	535					15
Front Street site				1,200		
Other sites				84	150	73
Total	$ 6,627	$	$	$ 29,432	$ 6,068	$ 9,954

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the Oregon Public Utility Commission (OPUC) approved our request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic, Portland Harbor and Front Street sites. The authorization, which was extended through January 2008 and expanded to include the

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Oregon Steel Mills site (see Legal Proceedings, below) and the Central Service Center site (discussed above), allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. Beginning in 2006, the OPUC authorized us to accrue interest on deferred 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 a cumulative basis, we have recognized a total of $57.1 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $21.0 million has been spent to date and $36.1 million is an outstanding liability. At June 30, 2007, we had a regulatory asset of $57.1 million, which includes $21.0 million for paid expenditures, $2.2 million in accrued interest and $33.9 million for additional environmental accruals for costs expected to be paid in the future. We will continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. We currently have an insurance receivable of $1.1 million, which is not included in the regulatory asset amount. We intend to pursue recovery of this insurance receivable and environmental regulatory deferrals from 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 some portion 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 legislation 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.

The following table summarizes the regulatory assets relating to environmental sites at June 30, 2007 and 2006 and December 31, 2006:

	Non-Current Regulatory Assets		
	June 30,		**Dec. 31,**
Thousands	**2007**	**2006**	**2006**
Gasco site	$ 27,187	$ 5,440	$ 10,336
Siltronic site	1,227	357	477
Portland Harbor site	26,676	15,585	16,769
Central Gas Storage Tanks site	545		
Front Street site	1,211		
Other sites	278	389	291
Total	$ 57,124	$ 21,771	$ 27,873

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 matters described below, cannot be predicted with certainty, we do not expect that the ultimate disposition of these matters will have a material adverse effect on our financial condition, results of operations or cash flows.

Independent Backhoe Operator Action**.** Since May 2004, several separate lawsuits were filed against NW Natural by independent backhoe operators who performed backhoe services for NW Natural under contract. Those lawsuits were consolidated into one case (*Law and Zuehlke, et. al. v. Northwest Natural Gas Co.,* 04-CV-728-KI, United States District Court, District of Oregon). Plaintiffs alleged wage and hour claims under the Fair Labor Standards Act and under state law. Plaintiffs claimed that they should have been considered employees, and sought overtime wages and interest, liquidated damages equal to the overtime award, civil penalties and attorneys fees and costs. Plaintiffs also alleged that the failure to classify them as employees constituted a breach of contract under and with respect to certain of NW Natural s employee benefits plans, programs and agreements. Plaintiffs sought an unspecified amount of damages for losses associated with that alleged breach of contract. Plaintiffs further alleged that the failure to classify them as employees resulted in an impermissible denial of benefits under the Employee Retirement Income Security Act of 1974 and sought to recover compensation equivalent to the benefits they would have received had they been covered employees under one of NW Natural s two defined benefit retirement plans. In May 2007, the District Court granted our Motion to Dismiss and Motion for Partial Summary Judgment on plaintiffs breach of contract and benefits claims. As a result of the Court s ruling, the only claims remaining in the case were the wage and hour claims under state and federal law. In July 2007, we settled those remaining claims as to all plaintiffs in the case. The Settlement and Release Agreement is fully executed and the settlement was approved and the case was dismissed with prejudice by the District Court in July 2007. The outcome of this litigation did not 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 Port s 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. In March 2005, motions to dismiss by ourselves and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that we were in violation of law was an affirmative defense that may be asserted at trial, but did not provide a sufficient basis for dismissal of the Port s claim. No date has been set for trial and discovery is ongoing. We received regulatory authorization from the OPUC for the deferral of environmental costs related to this site (see Regulatory and Insurance Recovery for Environmental Matters, above). 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.

12. 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 $2.3 million at June 30, 2007, which is related to employee benefit plan liabilities. The following table provides a reconciliation of net income to total comprehensive income for the three and six months ended June 30, 2007 and 2006.

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	**2007**	**2006**	**2007**	**2006**
Net income	$ 2,617	$ 1,994	$ 50,692	$ 43,027
Amortization of employee benefit plan liability, net of tax	32		64	
Total comprehensive income	$ 2,649	$ 1,994	$ 50,756	$ 43,027

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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, 2007 and 2006. 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 Northwest Natural Gas Company, which principally consist of our regulated local gas distribution business, our regulated gas storage business, and our other non-regulated businesses, which includes our wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation). 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 segment (gas storage) and our other non-regulated activities (other) (see Note 9).

Certain prior year balances on our consolidated balance sheets and statements of cash flows have been reclassified to conform with the current presentation. The financial statement classification was changed to reflect the current portion of regulatory assets and liabilities, which was included in a separate regulatory section on the balance sheet, and the current portion of fair value of non-trading derivative assets and liabilities, which was included under other assets or other liabilities. 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 2006 Form 10-K).

Executive Summary

Our strategy in 2007 is to remain focused on profitably growing our regulated gas utility and gas storage businesses. The gas utility is our largest business segment with approximately 97 percent of consolidated total assets. In 2006, the gas utility contributed 90 percent of consolidated net income. Factors critical to the success of the utility include maintaining a safe and reliable distribution system, acquiring an adequate supply of gas, providing distribution services at a competitive price, and being able to recover the operating and capital costs of the utility in the rates charged to customers. The utility is regulated by two state commissions, the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

Our gas storage segment represents approximately 3 percent of consolidated total assets. In 2006, the gas storage segment contributed 9 percent of consolidated net income. This business segment primarily provides firm and interruptible gas storage at our Mist underground storage facility to large interstate and intrastate customers using storage and related transportation capacity that is in excess of the utility s core (residential, commercial and industrial firm) customer requirements. Asset optimization is also part of the gas storage segment, with optimization services provided for the utility under an agreement with an independent energy marketing company. Factors critical to the success of our gas storage business segment include the ability to: develop additional storage capacity at competitive market prices; plan for the replacement of capacity that is expected to be recalled by the utility to serve its core customers in the future; and obtain timely and reasonable rate recovery for operating and capital costs.

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Highlights from the second quarter of 2007 include:

- Net income increased 31 percent, from $2.0 million to $2.6 million;
- Growth in net operating revenues from our regulated utility and gas storage businesses were major drivers to increased earnings with net operating revenues from the utility segment increasing 2 percent and 35 percent from the gas storage segment;
- A net increase of 16,096 utility customers in the 12 months ended June 30, 2007, for an annual growth rate of 2.6 percent;
- Operations and maintenance expense increased 2 percent;
- Cash flow from operations increased 34 percent to $180.3 million for the six months ended June 30, 2007, reflecting the stronger operating results and savings from lower gas costs;
- A new five year, $250 million revolving credit facility replaced existing credit agreements, providing increased liquidity and greater borrowing flexibility; and
- Also, during the six months ended June 30, 2007, total debt decreased by $87.5 million, including $29.5 million in repaid long-term debt, and share repurchases totaled $23.6 million.

Issues, Challenges and Performance Measures

There are a number of issues and challenges that affect our operations and financial performance. The most significant challenge we face in the near term continues to be managing the utility business in a period of high gas prices, increased demand and increased market volatility. Our gas acquisition strategy has been to secure sufficient supplies of natural gas to meet the needs of our utility s firm customers, but equally important is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon the market outlook and our core utility s load forecast. In 2006, we hedged the prices on a majority of our gas purchase requirements but at a slightly lower level than prior years based on the market outlook. As spot gas prices fell we were able to take advantage of the lower gas costs, resulting in commodity savings shared by our utility customers and shareholders. Currently, we expect gas prices to remain slightly higher than in the past few years, and about even with higher gas prices already reflected in our customers bills for the current Purchased Gas Adjustment (PGA) period which extends through October 2007. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but further price increases could change our earnings outlook and our competitive advantage. If gas prices increase, it could significantly affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses energy needs to alternative fuel sources. To address these competitive issues, we are continually developing new gas acquisition strategies to manage gas prices and meet market demands, and we are working on initiatives intended to improve operational efficiencies throughout the company through a comprehensive business process redesign effort (see Part II, Item 7., Executive Summary Issues, Challenges and Performance Measures, in the 2006 Form 10-K).

Another challenge includes our customer growth rate, which is largely driven by residential new construction. While we expect to continue to maintain a rate well above the national average for local gas distribution companies, a moderate slowdown in our customer growth rate through 2008 is expected due to economic conditions.

Strategic Opportunities

Business Process Redesign Update. During 2006, we initiated a project to evaluate our business processes and costs against our peers and to redesign those processes where long-term efficiencies could be gained. We targeted a number of areas where we could restructure to gain efficiencies, including more centralization and more standardized processes. As a result of these changes, to date we have reduced our employee count by about 10 percent since the beginning of 2006 and are on schedule to meet the anticipated workforce reductions of 100 to 200 employees by early 2008. We are also scheduled to complete and implement the first phase of a new enterprise resource planning system by January 1, 2008. For more information regarding our redesign efforts, see Part II, Item 7., Strategic Opportunities, in the 2006 Form 10-K.

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Pipeline Diversity. In September 2006, we announced that we were evaluating making a potential investment in a natural gas pipeline project that would connect TransCanada s Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. The proposed pipeline is intended to diversify our gas delivery options and enhance reliability for our customers, by providing an alternate transportation path for gas purchases in Alberta that currently move through the Northwest Pipeline system. In August, we entered into a joint venture with GTN with the purpose of developing, designing, permitting, constructing and owning the pipeline that would serve markets in Oregon and the western United States, subject to approval of the Federal Energy Regulatory Commission. See Part II, Item 5., Other Information, below.

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 or judgments involve regulatory cost recovery, revenue recognition, derivative instruments, pension assumptions, income taxes and environmental contingencies (see Part II, Item 7., Application of Critical Accounting Policies and Estimates, in the 2006 Form 10-K). There have been no material changes to the information provided in the 2006 Form 10-K with respect to the application of critical accounting policies and estimates, except as indicated below under Accounting for Contingencies. 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.

Accounting for Contingencies

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with Statement of Financial Accounting Standards (SFAS) No. 5, Accounting for Contingencies. We update estimates of loss contingencies, including estimates of legal defense costs, when such costs are probable of being incurred and are reasonably estimable, and related disclosures are updated when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depends upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results, developed in consultation with outside counsel and consultants when appropriate. When information is sufficient to estimate only a range of potential liabilities, and no point within the range is more likely than any other, we recognize an accrued liability at the low end of the range and disclose the range (see Contingent Liabilities, below). It is possible, however, that the range of potential liabilities could be significantly different than amounts currently accrued and disclosed, with the result that our financial condition and results of operations could be materially affected by changes in the assumptions or estimates related to these contingencies.

With respect to environmental liabilities and related costs, we accrued an additional $28.8 million of contingent liabilities in the second quarter of 2007 related to properties we own, or have previously owned, that require further study, investigation and possible remediation. These additional amounts accrued were developed with the assistance of outside consultants and legal counsel and were based on a review of information available from recently completed studies and negotiations involving several sites. Of the $28.8 million, $23.1 million is the present value of estimated future expenditures of $29.2 million over a period of two to eight years. Using sampling data, feasibility studies, existing technology and enacted laws and regulations, we estimated that the total future expenditures for environmental investigation, monitoring and remediation are $36.1 million as of June 30, 2007. It is our

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policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, then it is our policy to accrue at the lower end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated, and therefore we have recorded the liabilities at an amount that reflects the most likely estimate or the low end of the range.

In connection with environmental liability accrual during the second quarter of 2007, we recorded a corresponding regulatory asset of $28.8 million based on regulatory deferral authority from the OPUC of environmental costs associated with each of the sites affected. The authorization, which is currently extended through January 2008, allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. As of June 30, 2007, we have recognized a regulatory asset of $57.1 million which includes $23.2 million of actual expenditures to date and interest plus accruals for additional future estimated costs of $33.9 million. We will continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. If it is determined that both the insurance recovery and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. See Note 11.

Earnings and Dividends

Three months ended June 30, 2007 compared to June 30, 2006:

Net income was $2.6 million, or 10 cents per share, for the three months ended June 30, 2007, compared to $2.0 million, or 7 cents per share, for the same period last year.

The primary factors contributing to increased second quarter earnings were:

- increased utility volumes and net operating revenues (margin) from sales to residential and commercial customers from customer growth and weather that was 22 percent colder than the second quarter of 2006 (see Results of Operations Comparison of Gas Distribution Operations, below); and

- an increased contribution from gas storage due to an increase in firm storage capacity and revenues from our asset optimization arrangement.

Partially offsetting the above positive factors were:

- a lower margin contribution from regulatory sharing of gas cost savings, from $1.9 million in the second quarter of 2006 to $0.8 million in 2007;

- a fair value loss of $0.5 million from gas hedge contracts in the second quarter of 2007, which is expected to reverse prior to the end of the year, compared to a fair value gain of $0.3 million in the same period last year;

- increased depreciation expenses related to higher utility plant in service, which were partially offset by revenue increases related to cost recovery of pipeline integrity and bare steel capital expenditures that are tracked into rates on an annual basis through the PGA mechanism in Oregon; and

- increased income tax expense related to higher taxable income.

Six months ended June 30, 2007 compared to June 30, 2006:

Net income was $50.7 million, or $1.86 per share, for the six months ended June 30, 2007, compared to $43.0 million, or $1.56 per share, for the same period last year.

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Positive factors contributing to increased year-to-date earnings were:

- increased utility volumes and net operating revenues (margin) from sales to residential and commercial customers from customer growth and weather that was 7 percent colder than the first half of 2006 (see Results of Operations Comparison of Gas Distribution Operations, below);
- an increased margin contribution from regulatory sharing of gas cost savings, from $3.6 million in the first half of 2006 to $10.6 million in 2007; and
- a $2.2 million fair value gain from the reversal of a loss taken in the fourth quarter of 2006 related to derivative contracts that settled in 2007.

Partially offsetting the above positive factors were:

- increased depreciation expenses related to higher utility plant in service, which were partially offset by revenue increases related to cost recovery of pipeline integrity and bare steel capital expenditures that are tracked into rates on an annual basis through the PGA mechanism in Oregon;
- increased operations and maintenance expense mainly due to damages caused by heavy rain; and
- increased income tax expense related to higher taxable income.

Dividends paid on our common stock were 35.5 cents per share and 34.5 cents per share in the three-month periods ended June 30, 2007 and 2006, respectively, and 71 cents per share and 69 cents per share in the six-month periods ended June 30, 2007 and 2006, respectively. In July 2007, the Board of Directors declared a quarterly dividend on our common stock of 35.5 cents per share payable on August 15, 2007, to shareholders of record on July 31, 2007. The current indicated annual dividend rate is $1.42 per share.

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. 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 2006 Form 10-K.

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At June 30, 2007 and 2006 and at December 31, 2006, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		
	June 30,		Dec. 31,
Thousands	**2007**	**2006**	**2006**
Regulatory assets:			
Gas costs receivable	$	$ 6,966	$
Unrealized loss on non-trading derivatives[1]	17,429	18,025	30,798
Other	1,442	701	711
Total regulatory assets	$ 18,871	$ 25,692	$ 31,509
Regulatory liabilities:			
Gas costs payable	$ 28,380	$	$ 737
Unrealized gain on non-trading derivatives[1]	4,538	15,967	
Other	9,555	5,744	11,182
Total regulatory liabilities	$ 42,473	$ 21,711	$ 11,919

	Non-Current		
	June 30,		Dec. 31,
Thousands	**2007**	**2006**	**2006**
Regulatory assets:			
Gas costs receivable	$	$ 1,628	$
Unrealized loss on non-trading derivatives[1]	6,585	7,726	9,584
Income tax asset	68,086	66,757	67,141
Pension and other postretirement benefit obligations[2]	52,655		54,425
Environmental costs - paid[3]	23,183	16,025	19,113
Environmental costs - accrued but not yet paid[3]	33,941	5,746	8,760
Other	5,695	5,969	5,748
Total regulatory assets	$ 190,145	$ 103,851	$ 164,771
Regulatory liabilities:			
Gas costs payable	$ 5,859	$	$ 13,041
Unrealized gain on non-trading derivatives[1]	1,388	9,598	
Accrued asset removal costs	196,159	178,272	187,422
Other	2,432	2,113	2,519
Total regulatory liabilities	$ 205,838	$ 189,983	$ 202,982

1 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 Oregon PGA mechanism.

2 Pension and other postretirement costs are approved for regulatory deferral based on SFAS No. 87 and SFAS No. 106 expense included in customer rates from the most recent Oregon and Washington general rate cases (see Part II, Item 8., Note 7, in the 2006 Form 10-K).

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

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA mechanisms 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 (see Comparison of Gas Distribution Operations Cost of Gas Sold, below), 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 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 cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

The OPUC is currently conducting a formal review of the PGA process used by local distribution companies covering gas portfolio requirements, incentive sharing levels and filing requirements, among other items. The review is expected to be completed in early 2008. Implementation of any changes to the PGA mechanism is expected to be effective with the 2008 PGA filing.

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 (ROE) 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. In 2006, the ROE threshold after adjustment was 13.44 percent. In July 2007, the OPUC issued an order that no amounts will be required to be refunded to customers as a result of the 2006 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 into customer 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 a draft IRP with the WUTC on March 28, 2007 and we expect to file a draft IRP with the OPUC by December 2007.

Interstate Pipeline Rate Cases

On June 30, 2006, the two interstate pipeline companies that provide natural gas transportation to our distribution system filed for general rate increases with the Federal Energy Regulatory Commission (FERC). Changes in interstate pipeline transportation charges are subject to our PGA mechanism and are 100 percent passed through to customers in both Oregon and Washington. Both of the filed general rate increases were reflected in our 2006 PGA filings. In March 2007, the FERC approved a settlement in the Northwest Pipeline rate case, which resulted in an increase to our Northwest Pipeline transportation rates that was less than Northwest Pipeline s filed rate request. Northwest Pipeline issued refund credits to impacted shippers in April for the difference between the filed rates it placed into effect on January 1, 2007 and the settlement rates approved by the FERC in March. The amounts that are collected from our core customers reflecting the higher filed rates are being deferred and the difference between the filed rates and settlement rates will be returned to customers as part of the PGA process. This will reduce gross revenues and cost of sales but will have no impact on our results of operations. The transportation rates currently included in our customers rates for GTN are still being litigated by GTN in their rate case. See Part II, Item 7., Results of Operations Regulatory Matters Interstate Pipeline Rate Cases, in the 2006 Form 10-K.

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Utility Regulation Legislation

During 2005, the Oregon legislature passed legislation, effective January 1, 2006, intended to ensure that utilities do not collect in rates more income taxes than they actually pay to taxing authorities. Under this law, we are required to file a report in October each year that calculates the difference between the amount of income taxes paid to governmental entities compared to the amount of taxes we collected in rates in the previous year. For more information regarding this requirement, see Part II, Item 7., Results of Operations Regulatory Matters Utility Regulation Legislation, in the 2006 Form 10-K.

Based on our assessment of the rules developed to implement the law, we estimate that our 2007 Tax Report for the 2006 tax year will reflect a surcharge of about $1.6 million, which will result in a rate adjustment that provides for reimbursement of taxes paid from customers. It is anticipated that any amounts due from customers for the 2006 tax year would not be realized until after June 1, 2008, pending a review by the OPUC. For the 2007 tax year, we estimate that our 2008 tax report will also reflect a surcharge, and based on results through June 30, 2007, we have estimated the surcharge related to the six months ended June 30, 2007 to be about $2.8 million. We have determined that the recognition of this regulatory surcharge is uncertain because the OPUC has not completed its review of how the final rules will be applied to our 2006 and 2007 tax years. Our request for a Private Letter Ruling from the Internal Revenue Service on the issue of whether compliance with this law would cause us to fail to comply with provisions of federal tax law, including the normalization requirements of the Internal Revenue Code, is pending. Due to the regulatory uncertainty, our recovery in rates of the 2006 and 2007 estimated surcharge is not considered probable at this time and these amounts have been reserved. Given our current corporate structure and level of non-utility investments and activities, we expect that ongoing compliance with this law, as currently interpreted, will not have a material adverse effect on our financial condition, results of operations or cash flows.

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Comparison of Gas Distribution 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, 2007	Three months ended June 30, 2006	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	60,284	55,087	5,197
Commercial sales	42,570	40,010	2,560
Industrial - firm sales	11,692	15,518	(3,826)
Industrial - firm transportation	35,917	35,349	568
Industrial - interruptible sales	20,760	25,256	(4,496)
Industrial - interruptible transportation	63,177	58,358	4,819
Total utility volumes sold and delivered	234,400	229,578	4,822
Utility operating revenues - dollars:			
Residential sales	$ 86,106	$ 81,129	$ 4,977
Commercial sales	50,808	46,475	4,333
Industrial - firm sales	12,140	14,823	(2,683)
Industrial - firm transportation	1,470	1,169	301
Industrial - interruptible sales	17,595	20,384	(2,789)
Industrial - interruptible transportation	2,027	1,868	159
Other revenues	8,098	1,402	6,696
Total utility operating revenues	178,244	167,250	10,994
Cost of gas sold	114,732	105,007	(9,725)
Revenue taxes	4,387	4,196	(191)
Utility net operating revenues (margin)	$ 59,125	$ 58,047	$ 1,078
Utility margin:			
Residential sales	$ 36,204	$ 33,556	$ 2,648
Commercial sales	15,004	13,699	1,305
Industrial - sales and transportation	7,481	7,704	(223)
Miscellaneous revenues	1,341	1,145	196
Other margin adjustments	(89)	1,982	(2,071)
Margin before regulatory adjustments	59,941	58,086	1,855
Weather normalization mechanism	(1,562)	844	(2,406)
Decoupling mechanism	746	(883)	1,629
Utility margin	$ 59,125	$ 58,047	$ 1,078
Customers - end of period:			
Residential customers	578,957	563,750	15,207
Commercial customers	60,743	59,853	890
Industrial customers	941	942	(1)
Total number of customers - end of period	640,641	624,545	16,096
Actual degree days	698	572	

Percent colder (warmer) than average [1]	2%	(16%)

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Thousands, except degree day and customer data	Six months ended June 30, 2007	2006	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	223,181	214,399	8,782
Commercial sales	139,374	135,335	4,039
Industrial - firm sales	27,609	39,556	(11,947)
Industrial - firm transportation	79,388	65,091	14,297
Industrial - interruptible sales	46,424	67,820	(21,396)
Industrial - interruptible transportation	130,915	115,313	15,602
Total utility volumes sold and delivered	646,891	637,514	9,377
Utility operating revenues - dollars:			
Residential sales	$ 313,244	$ 295,443	$ 17,801
Commercial sales	168,850	159,522	9,328
Industrial - firm sales	28,795	37,999	(9,204)
Industrial - firm transportation	2,968	2,117	851
Industrial - interruptible sales	39,726	55,736	(16,010)
Industrial - interruptible transportation	4,120	3,727	393
Other revenues	11,166	(38)	11,204
Total utility operating revenues	568,869	554,506	14,363
Cost of gas sold	360,194	360,391	197
Revenue taxes	14,001	13,724	(277)
Utility net operating revenues (margin)	$ 194,674	$ 180,391	$ 14,283
Utility margin:			
Residential sales	$ 117,240	$ 111,904	$ 5,336
Commercial sales	47,342	45,476	1,866
Industrial - sales and transportation	15,860	16,190	(330)
Miscellaneous revenues	2,980	2,648	332
Other margin adjustments	10,862	3,422	7,440
Margin before regulatory adjustments	194,284	179,640	14,644
Weather normalization mechanism	(1,454)	2,686	(4,140)
Decoupling mechanism	1,844	(1,935)	3,779
Utility margin	$ 194,674	$ 180,391	$ 14,283
Actual degree days	2,550	2,386	
Percent colder (warmer) than average [1]		(6%)	

[1] Average weather represents the 25-year average degree days, as set in our last Oregon general rate case.

Certain amounts in prior years have been reclassified to conform to the current year presentation. These reclassifications had no impact on prior year results of operations. See Note 1.

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 order to offset the potential volatility in utility earnings caused by weather and declining consumption due to conservation, we obtained OPUC approval of a conservation tariff that adjusts margin up or down based on changes in residential and commercial customer consumption and a weather normalization mechanism that adjusts customer bills, and our margin, based on above- or below-average temperatures during the winter heating season (see

Regulatory Matters Rate Mechanisms, above, and Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2006 Form 10-K).

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Three months ended June 30, 2007 compared to June 30, 2006:

Utility operations resulted in a net loss of $0.1 million, or less than 1 cent per share, in the second quarter of 2007 compared to net income of $0.2 million, or 1 cent per share, in 2006. Net income from utility operations is typically low during the second quarter due to the reduced use of natural gas for space heating in the spring and early summer. Total utility volumes sold and delivered in the second quarter of this year increased by 2 percent over last year, and total utility margin increased by 2 percent.

Six months ended June 30, 2007 compared to June 30, 2006:

In the first half of 2007, utility operations contributed $46.0 million, or $1.69 per share, compared to $39.7 million, or $1.44 per share in 2006. Total utility volumes sold and delivered in the first half of this year increased by 1 percent over last year, while total utility margin increased by 8 percent.

Volume increases in both of the 2007 periods were due mainly to weather that was colder than the 2006 periods, but in line with average weather, and residential and commercial customer growth, which slowed but remained strong with a net increase of 16,096 customers since June 30, 2006, or an annual growth rate of 2.6 percent. Our growth rate remains above the national average for local gas distribution companies, despite recent economic conditions that have moderately slowed the level of new construction in our service territory. In the three years ended December 31, 2006, more than 58,400 customers were added, representing an average annual growth rate of 3.4 percent. The margin increase in the first half of the year was driven primarily by savings in the cost of gas (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. Approximately 10 percent of our eligible Oregon customers 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-month periods ended June 30, 2007 and 2006.

Three months ended June 30, 2007 compared to June 30, 2006:

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

- sales volumes were 8 percent higher as a result of weather that was 22 percent colder weather than last year; and

- operating revenues were 7 percent higher due to higher sales volumes and higher billing rates, which reflect the higher gas costs in the PGA effective November 1, 2006 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K).

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Six months ended June 30, 2007 compared to June 30, 2006:

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

- sales volumes were 4 percent higher as a result of customer growth and weather that was 7 percent colder than last year; and
- operating revenues were 6 percent higher due to higher sales volumes and higher billing rates, which reflect the higher gas costs in the PGA effective November 1, 2006 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K).

Total 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. Amounts reported as unbilled revenues reflect the increase or decrease in the balance of accrued unbilled revenues compared to the prior period 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, 2007, accrued unbilled revenue was $18.4 million, compared to $16.7 million at June 30, 2006, with the increase primarily reflecting colder weather toward the end of the second quarter of 2007 as compared to 2006.

Industrial Sales and Transportation

Industrial operating revenues include the cost of gas sold to sales service customers but not transportation service customers. Therefore, industrial customer switching between sales service and transportation service can cause swings in operating revenues. Because of this, we believe margin is a better indication of performance for the industrial sector.

Three months ended June 30, 2007 compared to June 30, 2006:

Total volumes delivered to industrial sales and transportation customers were down 2.9 million therms, or 2 percent, in the second quarter of 2007 as compared to the same period in 2006. Utility margin related to these customers was down $0.2 million, or 3 percent, over last year, primarily due to some temporary shut-downs of a few large customers.

Six months ended June 30, 2007 compared to June 30, 2006:

Total volumes delivered to industrial sales and transportation customers were down 3.4 million therms, or 1 percent, in the first half of 2007 as compared to the same period in 2006. Utility margin related to these customers was down $0.3 million, or 2 percent, over last year.

Other Revenues

Other revenues include miscellaneous fee income as well as utility revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferred gas costs (see Part II, Item 8., Note 1, Industry Regulation, in the 2006 Form 10-K).

Three months ended June 30, 2007 compared to June 30, 2006:

Other revenues were $8.1 million in the second quarter of 2007, compared to a $1.4 million in the second quarter of 2006, with the $6.7 million increase being primarily due to a $3.2 million increase in the contribution from decoupling regulatory deferrals and amortization, a $1.4 million increase in the contribution from weather normalization deferrals and a $1.7 million increase in gas storage credits.

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Six months ended June 30, 2007 compared to June 30, 2006:

Other revenues were $11.2 million in the first half of 2007, compared to a negligible net expense in the first half of 2006, with the increase being primarily due to a $9.0 million increase in the contribution from decoupling regulatory deferrals and amortization and a $1.7 million increase in gas storage credits.

Cost of Gas Sold

Natural gas commodity prices have risen significantly in recent years. The effects of higher commodity prices and price volatility on core utility customers are mitigated, in part, through our use of underground storage facilities, fixed-price commodity and financial hedge contracts and short term sales of excess gas supply and transportation capacity to off-system customers in periods when core utility customers do not require the full amount of contract gas supplies or firm pipeline capacity.

The total cost of gas sold in the second quarter of 2007 was $114.7 million, an increase of $9.7 million or 9 percent, compared to the second quarter of 2006. The total cost of gas sold in the first half of 2007 was $360.2 million, a decrease of $0.2 million, compared to the prior year. The cost of gas sold increased as volumes to residential and commercial customers increased, but was offset by the decrease in volumes sold to industrial sales customers. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity price hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

Under the PGA tariff in Oregon, our net income is affected by a sharing mechanism based on increases or decreases in purchased gas costs as compared to estimated gas costs included in customer rates (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K). In the second quarter of 2007, our share of gas cost savings contributed $0.8 million to margin, compared to a contribution to margin of $1.9 million in the second quarter of 2006. In the first half of 2007, our share of gas cost savings contributed $10.6 million to margin, compared to a $3.6 million contribution to margin in the first half of 2006. The net benefit to utility customers from aggregate gas cost savings amounted to $2.4 million and $24.1 million for the three- and six-month periods ended June 30, 2007, respectively. Because the volatility of gas prices cannot be predicted, the current contribution from this sharing mechanism may not be indicative of future results.

We use a natural gas commodity-price hedge program under the terms of our Financial Derivatives Policy to help manage our exposure to floating price gas purchase contracts (see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2006 Form 10-K, and Note 8, above). We realized net losses of $2.5 million from our financial hedges in the second quarter of 2007, compared to net losses of $10.5 million in the same period of 2006, but those losses were offset by lower gas purchase costs with no material impact on our results of operations. In the first half of 2007, we realized net losses of $10.0 million from our financial hedges, compared to net gains of $7.0 million in the first half of 2006.

Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, which are factored into our PGA deferrals and annual rate changes, but 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 of the net gain or loss deferred to a regulatory account and 33 percent recorded to current income. We recorded a $0.5 million increase in and a $2.2 million credit to the cost of gas in the second quarter and first six months of 2007, respectively, related to a fair value adjustment on financial derivative contracts that were entered into during the fourth quarter of 2006 after the 2006 PGA filing (see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2006 Form 10-K). In the final six months of 2007, we expect to recognize the reversal of $0.7 million of previously recognized losses as these derivative contracts settle.

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Business Segments Other than Gas Distribution Operations

Gas Storage

Net income from our gas storage business segment in the three and six months ended June 30, 2007 was $2.7 million and $4.5 million, respectively, or 10 cents and 16 cents per share, respectively. This compares to net income of $1.8 million, or 6 cents per share, and $3.3 million, or 12 cents per share, in the three and six months ended June 30, 2006, respectively. This current year increase was primarily due to increased firm storage capacity and increased revenues from our asset optimization arrangement with the independent energy marketing company (see Part II, Item 7., Results of Operations Business Segments Other Than Local Gas Distribution Gas Storage, in the 2006 Form 10-K).

Third-party optimization is provided pursuant to a contract with an independent energy marketing company, which assists in the optimization of the value of our storage and transportation capacity assets primarily through the use of commodity transactions. In Oregon, we retain 80 percent of the pre-tax income from interstate storage services and optimization activities when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such 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 interstate storage services and third-party optimization.

Other

The other business segment primarily consists of a wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including an investment in a leveraged aircraft lease (see Part II, Item 8., Note 2, Consolidated Subsidiary Operations and Segment Information, in the 2006 Form 10-K). Operating results from this segment for the three and six months ended June 30, 2007 consisted of net income of less than $0.1 million and $0.2 million, respectively, compared to a negligible loss for the three months ended June 30, 2006 and net income of $0.1 million for the six months ended June 30, 2006.

Our net investment balance in Financial Corporation at June 30, 2007 and 2006 was $2.9 million and $3.5 million, respectively. The $0.6 million decrease primarily reflects lower cash investments due to a cash dividend of $1.0 million paid to NW Natural in the third quarter of 2006. Our net investment balance in the leveraged aircraft lease at June 30, 2007 and 2006 was $4.8 million and $7.1 million, respectively, with the decrease primarily due to the receipt in March 2007 of the final payment due under the terms of the original twenty year lease agreement.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the second quarter of 2007 were $28.4 million, representing a $0.5 million, or 2 percent, increase over the second quarter of 2006. The following summarizes the major factors that contributed to the increase in operations and maintenance expense:

- a $0.4 million increase in contract work primarily due to outsourcing of seasonal staffing for the call center;
- a $0.2 million increase in certain employee benefit expenses; and
- a $0.3 million increase in injury and damage claims;
- offset, in part, by a $0.4 million decrease in bad debt expense due to improved collection results.

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Operations and maintenance expenses in the first half of 2007 were $57.3 million, representing a $1.1 million, or 2 percent, increase over the first half of 2006. The following summarizes the major factors that contributed to the increase in operations and maintenance expense:

- a $0.9 million increase in contract work primarily due to outsourcing of seasonal staffing for the call center; and
- a $1.0 million increase in damages, partially due to damages caused by heavy rains;
- offset, in part, by a $0.8 million decrease in bad debt expense due to improved collection results.

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, decreased $0.7 million, or 12 percent, in the three months ended June 30, 2007 over the same period in 2006, and decreased $0.5 million, or 3 percent, in the first half of 2007 compared to 2006. Regulatory fees decreased $0.7 million, or 12 percent, in the second quarter of 2007 compared to the second quarter of 2006 and $0.4 million, or 4 percent, in the first half of 2007 compared to 2006. The change in property and payroll taxes was negligible in both 2007 periods, compared to the 2006 periods.

Depreciation and Amortization

Depreciation and amortization expense increased by $1.0 million, or 6 percent, and by $2.0 million, or 6 percent, in the three- and six-month periods ended June 30, 2007, respectively, compared to the same periods in 2006. 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.

Other Income and Expense Net

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

Thousands	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Other income and expense - net:				
Gains from company-owned life insurance	$ 425	$ 414	$ 905	$ 1,797
Interest income	212	191	364	275
Other non-operating expense	(915)	(215)	(1,189)	(818)
Net interest expense on deferred regulatory accounts	(479)	(89)	(221)	(385)
Gain from equity investments	276	109	198	59
Total other income and expense - net	$ (481)	$ 410	$ 57	$ 928

The $0.9 million decrease in other income and expense net in the second quarter of 2007 compared to the same period in 2006 was primarily due to an increase in other non-operating expenses related to business development and interest on deferred regulatory accounts during the second quarter of 2007. During the quarter, we recorded an out of period adjustment related to accrued interest on a deferred regulatory asset. The adjustment reduced other income and expense net by $0.6 million in the quarter and $0.3 million in the six months ended June 30, 2007, neither of which was material. In the six months ended June 30, 2007, other income and expense net decreased $0.9 million compared to the same period in 2006 primarily due to a decrease in gains from company-owned life insurance.

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Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized decreased $0.4 million, or 4 percent, and $0.7 million, or 4 percent, in the three and six months ended June 30, 2007, respectively, compared to the same periods in 2006, primarily due to lower balances of total debt outstanding resulting from increased cash flows tied to strong operating results and gas cost savings.

Income Taxes

Income tax expense totaled $29.9 million in the six months ended June 30, 2007 compared to $24.5 million in the six months ended June 30, 2006. The effective tax rate was 37.1 percent in the first half of 2007 compared to 36.3 percent in the first half of 2006. The higher income tax expense in 2007 is due primarily to pre-tax book income of $80.6 million compared to $67.5 million for the same period in 2006. The increase in the effective tax rate was largely due to a $0.9 million decrease in non-taxable gains on life insurance.

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, 2007 and 2006 and at December 31, 2006, including short-term debt, was as follows:

	June 30,		Dec. 31,
	2007	2006	2006
Common stock equity	52.2%	51.4%	48.1%
Long-term debt	44.2%	41.4%	41.5%
Short-term debt, including current maturities of long-term debt	3.6%	7.2%	10.4%
Total	100.0%	100.0%	100.0%

The common stock equity percentages at June 30, 2007 and 2006 were higher as compared to December 31, 2006 primarily due to seasonal earnings and cash flows that reduced the combined long-term and short-term debt percentages.

In April 2007, the Board authorized an increase to the common stock share repurchase program, now aggregating up to 2.8 million shares, or up to $100 million in value, from the previously authorized levels of up to 2.6 million shares or up to $85 million in value. Purchases under this program are made in the open market or through privately negotiated transactions. See Financial Activities, below, and Part II, Item 2., Unregistered Sales of Equity Securities and Use of Proceeds, below.

Liquidity and Capital Resources

At June 30, 2007, we had $4.9 million of cash and cash equivalents compared to $6.6 million at June 30, 2006 and $5.8 million at December 31, 2006. 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 totaling $250 million available through May 31, 2012 (see Syndicated Lines of Credit, below). Proceeds from the issuance of long-term debt are used to finance capital expenditures and refinance maturing short-term or long-term debt.

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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.

Contractual Obligations

Since December 31, 2006, our estimated future contractual obligations have increased by about $11 million primarily due to contracts to outsource a portion of our construction work, including mains and services and locating services, and for the implementation of a new enterprise resource planning system, which were entered into in the ordinary course of business. Our contractual obligations at December 31, 2006 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2006 Form 10-K.

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes payable. 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, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by unsecured revolving loans (see Syndicated Lines of Credit, below, and Part II, Item 8., Note 6, in the 2006 Form 10-K). We had $42.1 million in commercial paper notes outstanding at June 30, 2007, compared to $55.8 million outstanding at June 30, 2006 and $100.1 million outstanding at December 31, 2006. Commercial paper balances are typically lower at the end of the first and second quarters compared to year-end due to collections from higher sales and the withdrawal of gas inventories from storage during the winter heating season. This year s outstanding balances were lower than last year primarily due to the gas cost savings discussed above in Results of Operations Comparison of Gas Distribution Operations Cost of Gas Sold.

Syndicated Lines of Credit

In May 2007, we entered into a credit agreement for unsecured revolving loans totaling $250 million with seven lenders under a syndicated facility (credit facility), replacing the prior $200 million bilateral credit agreements which were terminated. The new credit facility is available and committed for a term of five years expiring on May 31, 2012, which may be extended for additional one-year periods thereafter subject to lender approval. The credit facility allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit facility also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. The

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credit facility continues to be used primarily as back-up credit support for the notes payable issued under our commercial paper program. Commercial paper borrowing provides the liquidity to meet our working capital and interim financing requirements. Under the terms of the credit facility, we pay upfront fees, annual commitment fees and administrative agent fees, but we are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under the credit facility are based on our long-term unsecured debt ratings and on then-current market interest rates. All principal and unpaid interest under the credit facility is due and payable on May 31, 2012, subject to extensions, if any. There were no outstanding balances on this credit facility at June 30, 2007 or on prior credit agreements at June 30, 2006, or at December 31, 2006.

The credit facility requires that we maintain credit ratings with Standard & Poor s (S&P) and Moody s Investors Service, Inc. (Moody s) and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit facility 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 to accelerate the maturity of any amounts outstanding. We were in compliance with this covenant at June 30, 2007. Our recently replaced credit facilities required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at June 30, 2006 and December 31, 2006.

Credit Ratings

The table below summarizes our debt credit ratings from S&P and Moody s.

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

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. In July 2007, Moody s revised our ratings outlook from stable to positive. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

In May 2007, we redeemed $9.5 million of secured 6.80% Series B Medium Term Notes at maturity. In March 2007, we redeemed $20.0 million of secured 6.31% Series B Medium Term Notes at maturity. In June 2006, we redeemed $8.0 million of secured 6.05% Series B Medium-Term Notes at maturity.

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

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cash and non-cash adjustments to operating results. The overall change in cash flow from operating activities for the six months ended June 30, 2007 compared to the same period in 2006 was an increase of $45.6 million. The major factors contributing to the cash flow changes in the first six months of 2007 compared to the first six months of 2006 are as follows:

- an increase in net income added $7.7 million to cash flow;
- deferred gas costs, primarily related to gas cost savings for customers realized in the first quarter of 2007, increased cash by $22.1 million with the regulatory liability account increasing in the first half of 2007 compared to the regulatory receivable increasing in the first half of 2006; the liability balance and cash flow is expected to reverse when the cost savings are refunded to customers in utility rates under our PGA tariff to be effective starting in November 2007;
- an increase of $16.3 million resulting from a decrease in gas inventory balance in 2007 compared to 2006;
- a decrease of $13.2 million in 2007 compared to 2006 due to the realization of income taxes receivable in 2006; and
- a reduction in accounts payable in 2007 primarily due to lower gas prices around year end 2006 contributed $10.8 million.

Investing Activities

Cash requirements for investing activities in the first six months of 2007 totaled $52.5 million, up from $37.6 million in the same period of 2006. Cash requirements for utility plant totaled $40.8 million in the first six months of 2007, substantially unchanged from the $41.2 million expended in the same period of 2006.

Investments in non-utility property during the first six months of 2007 totaled $14.4 million, up from $0.2 million during the first six months of 2006, due primarily to amounts related to the capital improvements and expansion of our gas storage facilities and receipt of a $2.7 million payment due under the airplane leveraged lease agreement in 2007.

Our utility and non-utility capital expenditures are expected to total about $120 million in 2007, which includes amounts for an enterprise resource planning system and additional gas storage capital expenditures.

Financing Activities

Cash used in financing activities in the first six months of 2007 totaled $128.7 million, up from $97.6 million in the same period of 2006. The primary factors contributing to the $31.0 million increase were differences in debt financings and increased common stock repurchase activity. Debt financing consisted of a net decrease of $87.5 million in short-term and long-term debt outstanding in the first six months of 2007, compared to a net decrease of $78.9 million in 2006. Under our common stock repurchase program, we purchased 509,500 shares at a total cost of $23.2 million in the first half of 2007, compared to 35,400 shares at a total cost of $1.6 million in the first half of 2006.

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. 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 2006 Form 10-K.

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. For further discussion, see Part I, Item 7., Contingent Liabilities, in the 2006 Form 10-K.

We develop estimates of environmental liabilities and related costs based on currently available information, existing technology and environmental regulations. These costs include investigation, monitoring, and remediation. We received regulatory approval to defer and seek recovery of costs related to certain sites and believe the recovery of these costs is probable through the regulatory process. In accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, we have recorded a regulatory asset for the amount expected to be recovered. We intend to pursue recovery of these environmental costs from our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. During the second quarter of 2007, we accrued additional amounts totaling \$28.8 million based upon new information and analysis developed by management with the assistance of outside counsel and consultants. At June 30, 2007, a cumulative \$57.1 million in environmental cost deferrals has been recorded as a regulatory asset, consisting of \$23.2 million of costs paid to-date and interest plus \$33.9 million of accrued estimated future environmental expenditures. 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 (see Note 11, above).

Ratios of Earnings to Fixed Charges

For the six months and 12 months ended June 30, 2007 and the 12 months ended December 31, 2006, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 5.07, 3.69 and 3.40, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. Because a significant part of our business is of a seasonal nature, the ratio for the interim period is not necessarily indicative of the results for a full year.

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, including those of the OPUC and the WUTC, 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 and 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;

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

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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;

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

risks relating to the creditworthiness of customers, suppliers and financial derivative counterparties;

risks relating to our dependence on a single pipeline transportation provider for natural gas supply;

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

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

risks relating to the execution of our business process redesign;

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 the fair value of pension assets and on pension and other postretirement benefit costs;

- 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 price and supply risk, weather risk, and interest rate risk (see Part II, Item 7A. in the 2006 Form 10-K, Note 8, above, and Part II, Item 1A., Risk Factors, below).

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion 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, 2007 and 2006, notional amounts under these financial hedge contracts totaled $269.2 million and $341.9 million, respectively. If all of the financial hedge contracts had been settled on June 30, 2007, a loss of about $17.0 million would have been realized and recorded to a deferred regulatory account (see Note 8, above). 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, 2008. The $17.0 million unrealized loss is an estimate of future cash flows that are expected to be paid as follows: $12.7 million in the next twelve months and $4.3 million during the second twelve months. The amount realized will change based on market prices at the time contract settlements are fixed.

Credit Risk

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity hedge contracts was a negative $17.0 million at June 30, 2007. 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.

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, 2007**	**June 30, 2006**	**Dec. 31, 2006**
AAA/Aaa	$ (4,486)	$	$
AA/Aa	(12,559)	1,853	(40,955)
A/A			
BBB/Baa			
Total	$ (17,045)	$ 1,853	$ (40,955)

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of June 30, 2007, 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). There have been no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4.

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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

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2006 which could materially affect our business, financial condition or results of operations. The risks described in the 2006 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.

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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, 2007 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			1,367,800	$ 51,882,344
04/01/07 - 04/30/07	12,032	$ 45.25	115,000	(5,339,849)
05/01/07 - 05/31/07	18,443	$ 51.89		
06/01/07 - 06/30/07	1,861	$ 48.73	187,800	(8,814,597)
Total	32,336	$ 49.24	1,670,600	$ 37,727,898

(1) During the quarter ended June 30, 2007, 20,893 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 1,255 shares of our common stock were purchased in the open market during the quarter under equity-based programs. On February 27, 2007, we commenced a voluntary oddlot program through Georgeson Inc. which offered shareholders holding accounts with less than 100 shares of common stock the opportunity to either sell their shares or purchase an additional number of shares to round up to 100 shares of common stock in the account at the average closing price of our common stock over the offering period. During the three months ended June 30, 2007, a net of 10,188 shares were repurchased by us at the average closing price of $45.10 per share. The oddlot program expired on April 25, 2007. During the three months ended June 30, 2007, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of NW Natural s common stock through a repurchase program that has been extended annually. The purchases are made in the open market or through privately negotiated transactions. In April 2006, the Board increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. In April 2007, the Board extended the program through May 31, 2008 and increased the authorization from 2.6 million shares to 2.8 million shares and increased the dollar limit from $85 million to $100 million. During the three months ended June 30, 2007, 302,800 shares of our common stock were purchased pursuant to this program. Since the program s inception through June 30, 2007, we have repurchased 1,670,600 shares of common stock at a total cost of $62.3 million.

On March 29, 2007, we entered into a Stock Purchase Plan Engagement Agreement with our broker in order to establish a trading plan for our repurchase program that qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Exchange Act. That agreement expired on May 31, 2007. On June 29, 2007, we entered into a new Stock Purchase Plan Engagement Agreement with our broker to establish a trading plan for our repurchase program that also qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Exchange Act.

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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 24, 2007. At the 2007 Annual Meeting, three director-nominees were elected, as follows:

Director	Class	Term Expiring	Votes For	Votes Withheld
Tod R. Hamachek	II	2010	23,569,422	486,277
Kenneth Thrasher	II	2010	23,697,663	358,036
Russell F. Tromley	II	2010	23,574,156	481,543

The other seven directors whose terms of office as directors continued after the 2007 Annual Meeting are: Timothy P. Boyle, Martha L. (Stormy) Byorum, John D. Carter, Mark S. Dodson, C. Scott Gibson, Randall C. Papé and Richard G. Reiten.

The following matters also were acted upon at the meeting:

The Company s Restated Stock Option Plan was reapproved by the following vote:

FOR	AGAINST	ABSTAIN
22,525,722	1,131,341	398,635

The ratification of the Audit Committee s appointment of PricewaterhouseCoopers LLP as the company s independent public accountants for the year 2007 was approved by the following vote:

FOR	AGAINST	ABSTAIN
23,657,974	286,028	111,695

There were no broker non-votes on any of the matters voted upon at the meeting.

No other matters were acted upon at the meeting.

Item 5. OTHER INFORMATION

Two New Directors Elected

Effective July 27, 2007, the Board of Directors elected two directors to the Board: Jane L. Peverett, 49, President and Chief Executive Officer of British Columbia Transmission Corporation (BCTC), and George J. Puentes, 59, President of Don Pancho Authentic Mexican Foods Inc. Each of the directors was determined to be independent by the Board of Directors. The initial term of service for each director will expire on May 22, 2008, the date of the Company s Annual Meeting of Shareholders.

Pipeline Project Agreement

NW Natural previously reported that it was evaluating a potential pipeline project that would connect Gas Transmission Northwest s (GTN, a subsidiary of TransCanada Pipelines Limited) interstate transmission line to NW Natural s local gas distribution system to determine if there was sufficient interest by potential customers to justify construction of the pipeline (see Part II, Item 7., Strategic Opportunities Pipeline Diversity, in NW Natural s Annual Report on our 2006 Form 10-K. In connection with this evaluation, on August 3, 2007, NW Natural and GTN became co-owners of Palomar Gas Holdings, LLC (PGH), a Delaware limited liability company.

PGH holds 100 percent of the interest in Palomar Gas Transmission LLC (Palomar Gas Transmission), which was formed for the purpose of developing, designing, permitting, constructing and owning a natural gas pipeline (Palomar pipeline) that would serve markets in Oregon and the western United States. If constructed, the new pipeline is projected to begin service in late 2011.

TransCanada (through its subsidiary, GTN) and NW Natural are equal owners of PGH.

Prior to a closing of the debt financing for constructing the Palomar pipeline, either member may withdraw from PGH with the written consent of the other member or by voting in a certain manner on specified key decisions. Upon a default of a member under the agreement, the other member may purchase the defaulting party s interest.

Palomar Pipeline

Palomar Gas Transmission intends to develop and operate Palomar pipeline in accordance with an Operating Agreement which designates GTN as the operator of the pipeline. Building and operating the Palomar pipeline is subject to approval of the Federal Energy Regulatory Commission. Once a permit for the pipeline is obtained, the size of the pipeline would be determined based upon the level of binding customer commitments, up to 1.3 million Dth/day.

The planned initial phase of the Palomar pipeline would connect TransCanada s existing GTN interstate pipeline system in central Oregon with NW Natural s distribution system near Molalla, Oregon, approximately 30 miles southeast of Portland. NW Natural has entered into an agreement with Palomar Gas Transmission for 100,000 Dth/day of capacity on the proposed 110-mile eastern portion of the Palomar pipeline. The Palomar pipeline is intended to diversify NW Natural s gas delivery options and enhance reliability for NW Natural s customers. This pipeline would provide an alternate transportation path for gas purchases in Alberta that currently move through the Northwest Pipeline system.

The Palomar project is being designed so that, if a liquefied natural gas (LNG) terminal is constructed on the Columbia River, the pipeline could be extended to approximately 220 miles in total length to serve it. NorthernStar Natural Gas, the developer of the proposed Bradwood Landing LNG terminal on the Columbia River, may elect to use capacity on the Palomar pipeline.

NW Natural has also entered into an agreement with Palomar Gas Transmission for 100,000 Dth/day of capacity on the proposed western portion of the Palomar pipeline, if that section is built. NW Natural management believes the proposed western section of Palomar pipeline is important because it could provide an additional delivery and receipt path for Mist Gas Storage customers and access to a new, diversified source of gas supply.

Funding

Capital contributions for funding of the project will be shared equally between NW Natural and GTN. Initial development expenses related primarily to permitting over the next two years are expected to total up to $25 million to $30 million, of which NW Natural s share would be $12.5 million to $15 million. NW Natural management believes there is sufficient interest from potential pipeline users to warrant proceeding with the permitting phase of the project. The PGH management committee will determine at a later date whether to proceed with development of the project beyond the permitting phase.

If the project proceeds to the construction phase, it is anticipated that debt capitalization for construction of the proposed pipeline would be comprised of third-party non-recourse financing which would not require parent guarantees from the members. The commitment to construct the proposed pipeline is contingent upon (i) receiving necessary regulatory approvals, (ii) negotiating debt financing acceptable to the PGH management committee, (iii) execution of certain gas transportation agreements with NW Natural and other pipeline users and (iv) PGH management committee approval of the commitment to construct the project, including the schedule and amount of capital contributions. The estimated cost of the project is between $300 million and $350 million for the initial eastern 110-mile segment of the pipeline and a total of between $600 million and $700 million if fully developed, in current dollars.

Upon commencing commercial operations, ongoing operating costs are expected to be paid from the operating cash flow of Palomar Gas Transmission.

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 7, 2007

/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, 2007

Document	Exhibit Number
Statement re: Computation of Per Share Earnings	11
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