NORTHWEST NATURAL GAS CO
Form 10-Q
November 05, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 2008

OR

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

Commission File No. 1-15973

NORTHWEST NATURAL GAS COMPANY

(Exact name of registrant as specified in its charter)

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

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

(Address of principal executive offices) (Zip Code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of accelerated filer, large accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨	Smaller Reporting Company ¨

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

At October 31, 2008, 26,470,688 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 September 30, 2008

PART I. FINANCIAL 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 September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Operating revenues:				
Gross operating revenues	$ 109,702	$ 124,245	$ 688,650	$ 701,585
Less: Cost of sales	63,390	71,570	433,320	431,783
Revenue taxes	2,763	3,012	16,786	17,013
Net operating revenues	43,549	49,663	238,544	252,789
Operating expenses:				
Operations and maintenance	27,434	27,111	81,732	84,370
General taxes	5,739	6,389	20,595	19,557
Depreciation and amortization	18,113	17,173	53,775	50,930
Total operating expenses	51,286	50,673	156,102	154,857
Income (loss) from operations	(7,737)	(1,010)	82,442	97,932
Other income and expense - net	641	736	2,754	793
Interest charges - net of amounts capitalized	9,289	9,395	27,652	27,763
Income (loss) before income taxes	(16,385)	(9,669)	57,544	70,962
Income tax expense (benefit)	(6,265)	(3,761)	21,199	26,178
Net income (loss)	$ (10,120)	$ (5,908)	$ 36,345	$ 44,784
Average common shares outstanding:				
Basic	26,445	26,609	26,425	26,945
Diluted	26,445	26,609	26,582	27,109
Earnings (loss) per share of common stock:				
Basic	$ (0.38)	$ (0.22)	$ 1.38	$ 1.66
Diluted	$ (0.38)	$ (0.22)	$ 1.37	$ 1.65

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	**Sept. 30, 2008 (Unaudited)**	**Sept. 30, 2007 (Unaudited)**	**Dec. 31, 2007**
Assets:			
Plant and property:			
Utility plant	$ 2,113,898	$ 2,025,106	$ 2,052,161
Less accumulated depreciation	647,248	604,957	615,533
Utility plant - net	1,466,650	1,420,149	1,436,628
Non-utility property	72,919	61,025	67,149
Less accumulated depreciation and amortization	8,924	7,637	7,904
Non-utility property - net	63,995	53,388	59,245
Total plant and property	1,530,645	1,473,537	1,495,873
Current assets:			
Cash and cash equivalents	4,105	4,642	6,107
Accounts receivable	27,182	33,328	69,442
Accrued unbilled revenue	16,560	20,886	78,004
Allowance for uncollectible accounts	(1,752)	(1,726)	(2,890)
Regulatory assets	111,755	31,546	17,598
Fair value of non-trading derivatives	4,066	1,423	2,903
Inventories:			
Gas	91,797	79,607	71,079
Materials and supplies	10,840	9,264	8,865
Income taxes receivable	7,914	15,111	
Prepayments and other current assets	11,369	14,449	25,569
Total current assets	283,836	208,530	276,677
Investments, deferred charges and other assets:			
Regulatory assets	182,668	193,766	175,938
Fair value of non-trading derivatives	195	950	324
Other investments	67,884	51,014	54,070
Other	10,352	8,304	11,179
Total investments, deferred charges and other assets	261,099	254,034	241,511
Total assets	$ 2,075,580	$ 1,936,101	$ 2,014,061

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	Sept. 30, 2008 (Unaudited)	Sept. 30, 2007 (Unaudited)	Dec. 31, 2007
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 335,514	$ 340,352	$ 331,595
Earnings invested in the business	273,281	246,865	266,658
Accumulated other comprehensive income (loss)	(3,946)	(2,261)	(3,502)
Total common stock equity	604,849	584,956	594,751
Long-term debt	512,000	512,000	512,000
Total capitalization	1,116,849	1,096,956	1,106,751
Current liabilities:			
Notes payable	174,802	112,100	143,100
Long-term debt due within one year		5,000	5,000
Accounts payable	53,522	57,669	119,731
Taxes accrued	11,420	11,898	13,137
Interest accrued	11,138	11,247	2,827
Regulatory liabilities	23,882	51,481	61,326
Fair value of non-trading derivatives	109,012	27,350	14,829
Other current and accrued liabilities	28,523	22,381	29,794
Total current liabilities	412,299	299,126	389,744
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	223,088	215,981	206,340
Regulatory liabilities	221,927	206,642	213,764
Pension and other postretirement benefit liabilities	44,637	57,099	41,619
Fair value of non-trading derivatives	11,300	9,969	3,758
Other	45,480	50,328	52,085
Total deferred credits and other liabilities	546,432	540,019	517,566
Commitments and contingencies (see Note 11)			
Total capitalization and liabilities	$ 2,075,580	$ 1,936,101	$ 2,014,061

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30,	
Thousands	**2008**	**2007**
Operating activities:		
Net income	$ 36,345	$ 44,784
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	53,775	50,930
Deferred income taxes and investment tax credits	15,850	4,952
Undistributed earnings from equity investments	74	(174)
Deferred gas savings (costs) - net	(42,458)	26,572
Gain on sale of non-utility investments	(1,737)	
Non-cash expenses related to qualified defined benefit pension plans	2,301	3,301
Deferred environmental costs	(5,654)	(6,068)
Income from life insurance investments	(1,437)	(1,510)
Deferred regulatory and other	(2,278)	(2,262)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	102,566	114,844
Inventories of gas, materials and supplies	(22,693)	(10,743)
Income taxes receivable	(7,914)	(15,111)
Prepayments and other current assets	7,230	5,696
Accounts payable	(67,948)	(56,221)
Accrued interest and taxes	6,594	(1,009)
Other current and accrued liabilities	(664)	2,701
Cash provided by operating activities	71,952	160,682
Investing activities:		
Investment in utility plant	(66,761)	(65,296)
Investment in non-utility property	(5,841)	(18,330)
Proceeds from sale of assets	7,531	
Proceeds from life insurance	208	134
Contributions to non-utility investments	(5,250)	(2,688)
Other	(5,041)	2,662
Cash used in investing activities	(75,154)	(83,518)
Financing activities:		
Common stock issued, net of expenses	3,655	1,590
Common stock repurchased		(34,420)
Long-term debt retired	(5,000)	(29,500)
Change in short-term debt	31,702	12,000
Cash dividend payments on common stock	(29,722)	(28,693)
Other	565	734
Cash provided (used) in financing activities	1,200	(78,289)

Decrease in cash and cash equivalents	(2,002)	(1,125)
Cash and cash equivalents - beginning of period	6,107	5,767
Cash and cash equivalents - end of period	$ 4,105	$ 4,642
Supplemental disclosure of cash flow information:		
Interest paid	$ 19,413	$ 19,847
Income taxes paid	$ 14,800	$ 45,500

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Financial Statements and New Accounting Standards

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

The information presented in the interim consolidated financial statements is unaudited, but includes all material adjustments, including normal recurring accruals, that management considers necessary for a fair statement of the results for each period reported. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2007 Annual Report on Form 10-K (2007 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

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

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

New Accounting Standards

Adopted Standards

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

Relative to SFAS No. 157, the FASB issued FASB Staff Positions (FSP) 157-1, 157-2 and 157-3. FSP 157-1 amends SFAS No. 157 to exclude SFAS No. 13, Accounting for Leases, and its related interpretive accounting pronouncements that address leasing transactions. FSP 157-2 delays the effective date of the application of SFAS No. 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and liabilities except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis. FSP 157-3, issued and effective on October 10, 2008, clarifies the application of SFAS No. 157 when relevant observable inputs in active markets are not available.

We adopted SFAS No. 157 as of January 1, 2008, with the exception of the application of the statement to nonfinancial assets and liabilities. Nonfinancial assets and liabilities for which we have not yet applied the provisions of SFAS No. 157 include asset retirement obligations initially measured at fair value. The adoption of SFAS No. 157, FSP 157-1, FSP 157-2 and FSP 157-3 did not have, and are not expected to have, a material effect on our financial condition, results of operations or cash flows.

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

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

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

Recent Accounting Pronouncements

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

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

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

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

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

The adoption of SFAS No. 161 is not expected to have a material effect on our financial condition, results of operations or cash flows.

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

2. Segment Information

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

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

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

	Three Months Ended September 30,			
Thousands	**Utility**	**Gas Storage**	**Other**	**Total**
2008				
Net operating revenues	$ 39,277	$ 4,242	$ 30	$ 43,549
Depreciation and amortization	17,672	441		18,113
Income (loss) from operations	(11,066)	3,315	14	(7,737)
Net income (loss)	(12,359)	1,917	322	(10,120)
2007				
Net operating revenues	$ 44,683	$ 4,941	$ 39	$ 49,663
Depreciation and amortization	16,940	233		17,173
Income (loss) from operations	(5,468)	4,453	5	(1,010)
Net income (loss)	(8,644)	2,564	172	(5,908)

	Nine Months Ended September 30,			
Thousands	**Utility**	**Gas Storage**	**Other**	**Total**
2008				
Net operating revenues	$ 223,839	$ 14,578	$ 127	$ 238,544
Depreciation and amortization	52,684	1,091		53,775
Income from operations	70,262	12,065	115	82,442
Net income	27,440	6,758	2,147	36,345
Total assets at Sept. 30, 2008	1,990,073	71,478	14,029	2,075,580
2007				
Net operating revenues	$ 239,357	$ 13,299	$ 133	$ 252,789
Depreciation and amortization	50,252	678		50,930
Income from operations	85,992	11,893	47	97,932
Net income	37,385	7,022	377	44,784
Total assets at Sept. 30, 2007	1,871,781	55,929	8,391	1,936,101

3. Capital Stock

As of September 30, 2008, we had 100 million common shares authorized and 26,470,688 common shares outstanding.

We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2009 to repurchase up to an aggregate of 2.8 million shares or up to $100 million. During the nine months ended September 30, 2008, no shares of common stock were repurchased pursuant to this program. Since inception in 2000, a total of 2.1 million shares or $83.3 million have been repurchased.

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4. Stock-Based Compensation

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

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

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

Restated Stock Option Plan. In February 2008, options to purchase 114,050 shares were granted under the Restated SOP, with an exercise price equal to the closing market price of our common stock on the date of grant of $43.29 per share. In September 2008, an option to purchase 5,000 shares was granted under the Restated SOP, with an exercise price equal to the closing market price of our common stock on the date of grant of $51.09 per share. All shares granted in the nine months ended September 30, 2008 vest over the four-year period following date of grant and have a term of 10 years and 7 days. The fair value for the grants was estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

	February 2008	**September 2008**
Risk-free interest rate	2.8%	3.0%
Expected life (in years)	4.7	4.7
Expected market price volatility factor	18.4%	18.4%
Expected dividend yield	3.5%	2.9%
Forfeiture rate	3.8%	3.9%

As of September 30, 2008, there was $0.8 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2012.

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5. Long-Term Debt

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

Thousands	Sept. 30, 2008 (Unaudited)	Sept. 30, 2007 (Unaudited)	Dec. 31, 2007
Medium-Term Notes			
First Mortgage Bonds:			
6.50% Series B due 2008[1]	$	$ 5,000	$ 5,000
4.11% Series B due 2010	10,000	10,000	10,000
7.45% Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	10,000	10,000
7.13% Series B due 2012	40,000	40,000	40,000
8.26% Series B due 2014	10,000	10,000	10,000
4.70% Series B due 2015	40,000	40,000	40,000
5.15% Series B due 2016	25,000	25,000	25,000
7.00% Series B due 2017	40,000	40,000	40,000
6.60% Series B due 2018	22,000	22,000	22,000
8.31% Series B due 2019	10,000	10,000	10,000
7.63% Series B due 2019	20,000	20,000	20,000
9.05% Series A due 2021	10,000	10,000	10,000
5.62% Series B due 2023	40,000	40,000	40,000
7.72% Series B due 2025	20,000	20,000	20,000
6.52% Series B due 2025	10,000	10,000	10,000
7.05% Series B due 2026	20,000	20,000	20,000
7.00% Series B due 2027	20,000	20,000	20,000
6.65% Series B due 2027	20,000	20,000	20,000
6.65% Series B due 2028	10,000	10,000	10,000
7.74% Series B due 2030	20,000	20,000	20,000
7.85% Series B due 2030	10,000	10,000	10,000
5.82% Series B due 2032	30,000	30,000	30,000
5.66% Series B due 2033	40,000	40,000	40,000
5.25% Series B due 2035	10,000	10,000	10,000
	512,000	517,000	517,000
Less long-term debt due within one year		5,000	5,000
Total long-term debt	$ 512,000	$ 512,000	$ 512,000

(1) Redeemed at maturity in July 2008.

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6. Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income (loss)	$ (10,120)	$ (5,908)	$ 36,345	$ 44,784
Average common shares outstanding - basic	26,445	26,609	26,425	26,945
Additional shares for stock-based compensation plans			157	164
Average common shares outstanding - diluted	26,445	26,609	26,582	27,109
Earnings (loss) per share of common stock - basic	$ (0.38)	$ (0.22)	$ 1.38	$ 1.66
Earnings (loss) per share of common stock - diluted	$ (0.38)	$ (0.22)	$ 1.37	$ 1.65

For the three months ended September 30, 2008 and 2007, 163,555 and 189,827 common shares, respectively, were excluded from the calculation of diluted earnings per share because the effect of these additional shares on the net loss for both periods would have been anti-dilutive. For the nine months ended September 30, 2008, 359 common shares were excluded from the calculation of diluted earnings per share because the effect of these shares would have been anti-dilutive. For the nine months ended September 30, 2007, no common shares were excluded from the calculation of diluted earnings per share because the effect of all shares was dilutive.

7. 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:

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended September 30,			
Thousands	2008	2007	2008	2007
Service cost	$ 1,654	$ 2,212	$ 133	$ 84
Interest cost	4,302	4,054	349	329
Expected return on plan assets	(4,777)	(4,595)		
Amortization of loss	96	515		13
Amortization of prior service cost	314	400	48	52
Amortization of transition obligation			103	103
Net periodic benefit cost	1,589	2,586	633	581
Amount allocated to construction	(387)	(668)	(212)	(211)
Net amount charged to expense	$ 1,202	$ 1,918	$ 421	$ 370

	Pension Benefits		Other Postretirement Benefits	
	Nine Months Ended September 30,			

Thousands	**2008**	**2007**	**2008**	**2007**
Service cost	$ 4,962	$ 6,530	$ 398	$ 379
Interest cost	12,906	12,041	1,047	969
Expected return on plan assets	(14,331)	(13,867)		
Amortization of loss	288	1,592		15
Amortization of prior service cost	941	891	147	151
Amortization of transition obligation			309	309
Net periodic benefit cost	4,766	7,187	1,901	1,823
Amount allocated to construction	(1,175)	(1,716)	(643)	(623)
Net amount charged to expense	$ 3,591	$ 5,471	$ 1,258	$ 1,200

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

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Employer Contributions

Contributions to our pension and other postretirement benefit plans totaled $2.0 million and $1.8 million during the nine months ended September 30, 2008 and 2007, respectively. These contributions were made in the form of ongoing benefit payments to our unfunded, non-qualified benefit plans. We did not make and were not required to make cash contributions to our qualified, non-contributory defined benefit pension plans during 2008 due to our funded status, with plan assets funded at nearly 100 percent of the projected benefit obligation at December 31, 2007. However, we expect our funded status to be lower at December 31, 2008 due to declines in the market value of plan assets during 2008. We do not know the extent of the decline, if any, but the asset value decline may be partially offset by a decrease in projected benefit obligations due to higher discount rates used in measuring plan liabilities. The net impact on our funded status may require higher contributions than discussed in our 2007 Form 10-K. For additional discussion of estimated future payments, see Part II, Item 8., Note 7, in the 2007
Form 10-K.

8. Comprehensive Income

Items that are excluded from net income and charged directly to common stock equity are included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in common stock equity is $3.9 million at September 30, 2008, which is related to employee benefit plan liabilities and unrealized gains or losses from derivatives not included under regulatory assets and liabilities (see Note 10, below). The following table provides a reconciliation of net income to total comprehensive income for the three and nine months ended September 30, 2008 and 2007.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Thousands	**2008**	**2007**	**2008**	**2007**
Net income (loss)	$ (10,120)	$ (5,908)	$ 36,345	$ 44,784
Amortization of employee benefit plan liability, net of tax	55	32	165	96
Change in unrealized loss from derivatives, net of tax	(1,517)		(609)	
Total comprehensive income (loss)	$ (11,582)	$ (5,876)	$ 35,901	$ 44,880

9. Fair Value of Financial Instruments

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

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

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

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

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

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

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

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

Thousands	**Fair Value Measurements**	
Hierarchy	**Description of Derivative Inputs**	**Fair Value, net**
Level 1	Quoted prices in active markets	$
Level 2	Significant other observable inputs	(116,051)
Level 3	Significant unobservable inputs	
		$ (116,051)

10. Use of Financial Derivatives

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

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

	September 30, 2008		**September 30, 2007**		**Dec. 31, 2007**	
Thousands	**Current**	**Non-Current**	**Current**	**Non-Current**	**Current**	**Non-Current**
Fair Value Gain (Loss), net*:						
Natural gas commodity contracts	$ (104,767)	$ (8,741)	$ (26,330)	$ (9,019)	$ (12,099)	$ (2,104)
Interest rate hedge contract		(2,364)				(1,330)
Foreign currency forward purchase contracts	(179)		403		173	
Total	$ (104,946)	$ (11,105)	$ (25,927)	$ (9,019)	$ (11,926)	$ (3,434)

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

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In the three and nine months ended September 30, 2008, we realized net gains of $2.1 million and $23.4 million, respectively, from the settlement of natural gas hedge contracts, which were recorded as reductions to the cost of gas, compared to net losses of $15.5 million and $25.6 million, respectively, in the same periods of 2007, which were recorded as increases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts. The interest rate hedge contract outstanding at December 31, 2007 and September 30, 2008 qualifies as a cash flow hedge for accounting purposes, and changes in the value of this cash flow hedge are included in other comprehensive income, except in cases when the hedge gain or loss is included in regulatory assets or liabilities, assuming regulatory deferral to future utility rates. On September 30, 2008, we extended the maturity date on our interest rate swap to December 1, 2008, which resulted in a related hedge ineffectiveness of $0.2 million. This hedge ineffectiveness was recorded to regulated liabilities as we are generally required to defer these unrealized hedge gains and losses related to utility debt issuances in accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation (see Part II, Item 8., Note 1 and Note 11, in the Form 10-K). There were no realized gains or losses from the interest rate hedge during the three or nine months ended September 30, 2008.

As of September 30, 2008, all outstanding natural gas hedge contracts were scheduled to mature on or before October 31, 2010. The maturity date for our interest rate swap contract is December 1, 2018, but we expect to settle this contract concurrent with our next long-term debt issuance.

11. Commitments and Contingencies

Environmental Matters

We own, or have previously owned, properties that are likely to require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. See Part II, Item 8., Note 12, in the 2007 Form 10-K. The status of each site currently under investigation is provided below.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality s (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised Upland Remediation Investigation Report and submitted it to the ODEQ for review. We have a net liability accrued of $20.2 million at September 30, 2008 for the Gasco site, which is estimated at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We are currently working with the ODEQ to develop a study of manufactured gas plant wastes on the uplands at this site. The net liability accrued at September 30, 2008 for the Siltronic site is $1.1 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes the area adjacent to the Gasco and Siltronic sites. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS), completion of which is currently expected in 2009. The EPA and the Lower Willamette Group are conducting focused studies on approximately nine miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. In 2007, we received a revised estimate and updated our estimate for additional expenditures related to RI/FS development and environmental remediation. In August 2008, we signed a cooperative agreement to participate in a phased natural resource damage assessment, with the intent to identify what, if any, additional information is necessary to estimate further liabilities sufficient to support an early restoration-based settlement of natural resource damage claims. As of September 30, 2008, we have a net liability accrued of $13.2 million for this site, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

In April 2004, we entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the river sediments adjacent to the Gasco site. We completed the removal of the tar deposit in the Portland Harbor in October 2005, and on November 5, 2005 the EPA approved the completed project. The total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $10.8 million. To date, we have paid $10.0 million on work related to the removal of the tar deposit. As of September 30, 2008, we have a net liability accrued of $0.8 million for our estimate of ongoing costs related to the tar deposit removal.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (the Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2007, we received notice that this site was added to the ODEQ s list of sites where releases of hazardous substances have been confirmed and its list where additional investigation or cleanup is necessary. We are currently performing an environmental investigation of the property with the ODEQ s Independent Cleanup Pathway. As of September 30, 2008, we have recorded an estimated liability of $0.5 million for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. Although it is outside the geographic scope of the current Portland Harbor site sediment studies, the EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that it could be managed separately from the Portland Harbor site under ODEQ authority. As of September 30, 2008, we accrued an estimated liability of $0.3 million for the study of the site, which will include investigation of sediments and provide a report of historical upland activities. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Oregon Steel Mills site. See Legal Proceedings, below.

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

	Current Liabilities			Non-Current Liabilities		
Thousands	**Sept. 30, 2008**	**Sept. 30, 2007**	**Dec. 31, 2007**	**Sept. 30, 2008**	**Sept. 30, 2007**	**Dec. 31, 2007**
Gasco site	$ 7,839	$ 3,066	$ 6,901	$ 12,378	$ 18,292	$ 14,342
Siltronic site	1,010	704		67		1,540
Portland Harbor site	744	845		13,276	10,258	14,821
Central Service Center site		534		529		529
Front Street site	318				1,200	
Other sites	3			84	85	167
Total	$ 9,914	$ 5,149	$ 6,901	$ 26,334	$ 29,835	$ 31,399

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer and seek recovery of unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, this authorization has been extended through January 25, 2009. We expect to file for another extension in January 2009.

On a cumulative basis, we have recognized a total of $69.4 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $33.2 million has been spent to date and $36.2 million is reported as an outstanding liability. At September 30, 2008, we had a regulatory asset of $64.7 million, which includes $28.3 million of total paid expenditures to date, $31.0 million for additional environmental costs expected to be paid in the future and accrued interest of $5.4 million. We believe the recovery of these deferred charges is probable through the regulatory process. We intend to pursue recovery of an insurance receivable and environmental regulatory deferrals from insurance carriers under our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of most of our environmental costs probable based on a combination of factors including: a review of the terms of our insurance policies; the financial condition of the insurance companies providing coverage; a review of successful claims filed by other utilities with similar gas manufacturing facilities; and Oregon law that allows an insured party to seek recovery of all sums from one insurance company. We have initiated settlement discussions with a majority of our insurers but continue to anticipate that our overall insurance recovery effort will extend over several years.

We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we do not expect to have completed our insurance recovery efforts during that time period. As such we have classified our regulatory assets for environmental cost deferrals as non-current. The following table summarizes the non-current regulatory assets relating to environmental sites at September 30, 2008 and 2007 and December 31, 2007:

	Non-Current Regulatory Assets		
Thousands	**Sept. 30, 2008**	**Sept. 30, 2007**	**Dec. 31, 2007**
Gasco site	$ 30,003	$ 27,492	$ 29,042
Siltronic site	2,287	1,227	2,227
Portland Harbor site	31,091	26,775	30,869
Central Service Center site	545	1,226	545
Front Street site	338		
Other sites	395	807	371
Total	$ 64,659	$ 57,527	$ 63,054

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Legal Proceedings

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

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

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

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

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

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

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

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on earnings. All references in this section to earnings per share are on the basis of diluted shares (see Part II, Item 8., Note 1, Earnings Per Share, in our 2007 Annual Report on Form 10-K (2007 Form 10-K)).

Executive Summary

Results for the third quarter of 2008 include:

- a consolidated net loss of $10.1 million compared to a net loss of $5.9 million last year;
- a decrease in net operating revenues (margin) of $5.4 million from our utility segment and $0.7 million from our gas storage segment;
- a net gain of 15,503 utility customers over the last 12 months, for a growth rate of 2.4 percent;
- a decrease in cash flow from operations for the nine months ended September 30, 2008 from $160.7 million last year to $72.0 million this year, primarily reflecting higher gas purchase costs;
- a first place ranking in the nation among gas utilities by the 2008 J.D. Power and Associates Residential Customer Satisfaction Survey; and

an increase in our quarterly dividend of 2 cents a share, or 5 percent, to 39.5 cents a share payable on November 14, 2008 to shareholders of record on October 31, 2008.

Issues, Challenges and Performance Measures

Managing the business in a period of gas price volatility. In recent years, natural gas commodity prices have been volatile. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility s core (residential, commercial and industrial firm) customers. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon our core utility s gas load forecast. We have hedged the majority of our gas costs for the next gas contract year beginning November 1, 2008, and we believe we have sufficient supplies of natural gas to meet the needs of our core customers (see Part I, Item 1., Gas Supply, Storage and Transportation Capacity Core Utility Market Basic Supply, in the 2007 Form 10-K). Although gas prices reached historically high levels during the third quarter of 2008, recently the price of natural gas has declined and is now below the rates embedded in our new PGA. Gas costs above those set in our annual PGA tariff may negatively impact earnings due to an incentive sharing mechanism in Oregon, whereby we are required to recognize expense for a portion of actual purchased gas costs in excess of those assumed in setting rates (see Results of Operations Regulatory Matters Rate Mechanisms below). Higher gas costs are also likely to affect our competitive advantage by reducing our ability to add residential and commercial customers and potentially causing industrial customers to shift their energy needs to alternative fuel sources. On October 21, 2008, the Oregon Public Utility Commission (OPUC) modified the PGA incentive cost sharing mechanism to allow us to annually select a cost sharing ratio, which along with hedging strategies and gas inventories in storage enables us to manage and mitigate, within limits, the risk exposure due to higher gas costs (see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, below). We believe this modification better aligns customer and shareholder interests. There has been no change to the Washington PGA mechanism.

Economic weakness and credit market stress. The overall weakness in the U.S. economy, including turmoil in the credit markets, weakness in the housing market, and volatility in energy prices, has resulted in significant negative pressure on consumer demand and business spending. These conditions have resulted in slower utility customer growth, which was 2.4 percent over the last 12 months compared to 2.6 percent a year ago, and we expect the year-over-year decline to continue for the remainder of 2008 and may continue to decline into 2009. We also could experience higher bad debt expense due to weakness in the economy and higher interest costs due to unfavorable market conditions.

Our ability to fund strategic investment opportunities is dependent upon our ability to access capital markets and maintain working capital sufficient to meet operating requirements. Our strategy has been, and continues to be, focused toward: maintaining a strong balance sheet; providing sufficient operating liquidity; monitoring and managing critical business risks; and securing, as needed, proceeds from the issuance of equity or debt securities in order to fund utility and business development capital expenditures. To help mitigate the effect of the negative trends referred to above, we expect to manage costs, extend our short-term debt maturities, maintain higher cash balances, potentially request increases in the aggregate commitment amount under our credit facility, and access capital markets to secure proceeds from the issuance of long-term securities in advance of capital expenditure requirements. If we are unable to secure debt financing to fund certain strategic opportunities, we would delay making those investments until market conditions improve.

We believe that, despite the current economic and credit market environment, our financial condition, including our liquidity position, is strong and we can access capital at reasonable costs. We currently have a $250 million committed credit facility and no long-term debt maturing in the remainder of 2008 or 2009. See Financial Condition Liquidity and Capital Resources, and Part II, Item 1A., Risk Factors, below.

Strategic Opportunities

Business Process Improvements. To address our economic and competitive challenges, we continue to evaluate business processes and costs in our new operating model and improve those processes where efficiencies can be gained. Our goal is to integrate and streamline operations and provide our employees with new technology tools that enable us to become more effective and efficient. In early 2008, we implemented the first phase of our new enterprise resource planning (ERP) system and began work on a second phase, which is expected to be completed by early 2009. Our new ERP system provides a comprehensive suite of business application software which interfaces with our existing customer information and gas management systems. We expect the new ERP system to improve overall operating efficiencies by automating:

- the integration of data;
- control procedures with auditable financial and operational workflow processes; and
- more of the monthly closing process.

In 2006, we initiated a project to automate the reading of gas meters on approximately one-third of our customers meters. The meters equipped with this technology transmit usage data to receiving devices located in our vehicles as they are driven in the area, eliminating the need for manual reading of customers meters. In the second quarter of 2008, we initiated a project to automate the reading of gas meters for our remaining customers, and we expect to seek regulatory recovery for the corresponding estimated $30 million capital cost. In early 2008 we also initiated an automated dispatching system, which provides integrated planning and scheduling with global positioning capabilities to more effectively collect and distribute data. These technology investments and other initiatives are expected to facilitate process improvements and contribute to operational efficiencies throughout NW Natural. For more information regarding our new operating model, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

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Pipeline Diversification. Palomar Gas Transmission, LLC (PGT) is a wholly owned subsidiary of Palomar Gas Holdings, LLC (PGH) of which NW Natural and GTN are each 50 percent members. The Palomar project, a natural gas transmission pipeline, would extend west and south from an interconnection with GTN s existing interstate transmission facilities near Madras, Oregon to an interconnection with NW Natural s gas distribution system near Molalla, Oregon then extending to additional interconnections to the west and north, including possible interconnections to one of the several liquefied natural gas (LNG) facilities proposed to be built on the Columbia River. Palomar would diversify NW Natural s delivery options and thus enhance the reliability of service to our customers by providing an alternate transportation path for gas purchases in different regions in Canada and the U.S. Rocky Mountains. The Palomar pipeline would be regulated by the Federal Energy Regulatory Commission (FERC). Currently, the Palomar project is in the pre-filing stage of the permitting process at FERC and PGT plans to file for a Certificate of Public Convenience and Necessity with FERC during the fourth quarter of 2008.

The PGH members continue to evaluate the construction and operation of Palomar and will determine later whether to proceed with development of Palomar beyond the permitting phase. The planning and permitting phase of Palomar is expected to extend through 2010. We have revised our estimate of the total cost for permitting and planning through FERC certification to be between $40 million and $45 million, and 50 percent of this amount would be invested by us in proportion to our ownership interest. We also revised our cost estimate for the entire 220-mile pipeline, if constructed, to be between $700 million and $800 million, of which our current 50 percent share would be between approximately $350 million and $400 million with the increase due to the price of steel and other material costs. For more information regarding our pipeline diversification efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

Gas Storage Development. In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. We formed a subsidiary, Gill Ranch, to plan, develop and operate the facility. Based on a strong level of interest from prospective customers in response to an open season to gauge interest in the storage facility, on July 29, 2008 Gill Ranch filed an application with the California Public Utilities Commission for a Certificate of Public Convenience and Necessity. We expect to receive a decision by the end of 2009. We revised the estimate for our share of the total cost, which includes 75 percent of the initial 20 billion cubic feet phase of storage development and approximately 25 miles of pipeline to be constructed during the 2008 to 2010 period, to be between $160 million and $180 million, with the increased estimate mainly due to higher equipment costs and reservoir development expense. For more information regarding our gas storage development efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

Earnings and Dividends

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

Net income was a loss of $10.1 million, or 38 cents per share, for the three months ended September 30, 2008, compared to loss of $5.9 million, or 22 cents per share, for the same period last year.

The primary factors contributing to the higher third quarter net loss were:

- a $1.8 million loss in utility margin from our regulatory share of gas cost increases, compared to a margin gain of $0.2 million in the third quarter of 2007;
- a $0.4 million net decrease in utility margin from industrial customers;
- a $3.3 million decrease in utility margin from a regulatory adjustment for income taxes paid, as we first recorded this adjustment in September 2007 for fiscal year 2006 and year-to-date 2007 operating results; and
- a $0.6 million decrease in net income from our gas storage segment.

Partially offsetting the above factors contributing to the higher net loss were:

a $0.4 million increase in utility margin from sales to residential and commercial customers, after our decoupling mechanism adjustment, due to 2.4 percent customer growth; and

a $2.5 million increase in income tax benefit due to lower taxable income.

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Nine months ended September 30, 2008 compared to September 30, 2007:

Net income was $36.3 million, or $1.37 per share, for the nine months ended September 30, 2008, compared to $44.8 million, or $1.65 per share, for the same period last year.

The primary factors contributing to lower year-to-date earnings were:

- a $7.5 million loss in 2008 in utility margin from our regulatory share of gas cost increases, compared to a gain of $10.8 million in the third quarter of 2007; and
- a $2.9 million decrease in utility margin from a regulatory adjustment for income taxes paid, as we first recorded this adjustment in September 2007 for fiscal year 2006 and year-to-date 2007 operating results.

Partially offsetting the above factors were:

- a $6.4 million increase in utility margin from increased sales to residential and commercial customers, after weather and decoupling mechanism adjustments, due to customer growth and colder weather than 2007;
- a $2.7 million, or 3 percent, decrease in operations and maintenance expense primarily due to lower incentive compensation costs;
- a $1.1 million increase in other income after-tax from a gain on sale of our investment in an aircraft; and
- a $5.0 million decrease in income tax expense related to lower taxable income.

Dividends paid on our common stock were 37.5 cents per share and 35.5 cents per share in the three months ended September 30, 2008 and 2007, respectively, and $1.125 per share and $1.065 per share in the nine months ended September 30, 2008 and 2007, respectively. In October 2008, the Board of Directors declared a quarterly dividend on our common stock of 39.5 cents per share, payable on November 14, 2008 to shareholders of record on October 31, 2008. The current indicated annual dividend rate is $1.58 per share.

Application of Critical Accounting Policies and Estimates

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

- regulatory cost recovery and amortizations;
- revenue recognition;
- derivative instruments and hedging activities;

pensions;

income taxes; and

environmental contingencies.

There have been no material changes to the information provided in the 2007 Form 10-K with respect to the application of critical accounting policies and estimates (see Part II, Item 7., Application of Critical Accounting Policies and Estimates, in the 2007 Form 10-K). Management has discussed the estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board.

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

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates and systems of accounts established by the OPUC, the Washington Utilities and Transportation Commission (WUTC) and the FERC. The OPUC and WUTC also regulate our issuance of securities. Typically, about 90 percent of our utility gas deliveries and operating revenues are derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the Oregon and Washington economies in general and by the pace of growth in residential and commercial markets in particular, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant. See Part II, Item 7., Results of Operations Regulatory Matters, in the 2007 Form 10-K.

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

	Current		
Thousands	Sept. 30, 2008	Sept. 30, 2007	Dec. 31, 2007
Regulatory assets:			
Unrealized loss on non-trading derivatives[1]	$ 109,012	$ 27,104	$ 14,788
Pension and other postretirement benefit obligations[2]	1,912	3,567	1,912
Other	831	875	898
Total regulatory assets	$ 111,755	$ 31,546	$ 17,598
Regulatory liabilities:			
Gas costs payable	$ 10,263	$ 37,581	$ 46,153
Unrealized gain on non-trading derivatives[1]	5,131	1,423	2,903
Other	8,488	12,477	12,270
Total regulatory liabilities	$ 23,882	$ 51,481	$ 61,326

	Non-Current		
Thousands	Sept. 30, 2008	Sept. 30, 2007	Dec. 31, 2007
Regulatory assets:			
Gas costs receivable	$ 278	$	$
Unrealized loss on non-trading derivatives[1]	11,300	9,969	3,758
Income tax asset	69,547	68,086	68,649
Pension and other postretirement benefit obligations[2]	25,728	48,203	27,152
Environmental costs - paid[3]	33,610	25,181	27,956
Environmental costs - accrued but not yet paid[3]	31,049	32,346	35,098
Other	11,156	9,981	13,325
Total regulatory assets	$ 182,668	$ 193,766	$ 175,938
Regulatory liabilities:			
Gas costs payable	$	$ 2,769	$ 6,290
Unrealized gain on non-trading derivatives[1]	195	950	324
Accrued asset removal costs	219,095	200,590	204,886
Other	2,637	2,333	2,264
Total regulatory liabilities	$ 221,927	$ 206,642	$ 213,764

(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 or refundable through utility rates as part of our PGA.

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

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

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established each year under 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, interstate pipeline demand charges, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year.

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

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On October 21, 2008, the OPUC approved changes to our PGA sharing mechanism. Under the Oregon PGA mechanism, we collect an amount for purchased gas costs based on estimates included in rates, and 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. Under the prior Oregon PGA incentive sharing mechanism, 67 percent of the difference was to be deferred such that the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower purchased gas costs.

Under the new mechanism, we are required to select, by August 1 of each year, either an 80 percent-20 percent or 90 percent-10 percent customer-utility sharing of commodity cost differences. As was the case under the prior mechanism, we will be subject to an annual earnings review to evaluate the utility s financial performance. We will have the ability to earn up to an earnings threshold of 150 basis points above our currently authorized return on equity if we select the 80-20 sharing ratio, or up to 100 basis points above the currently authorized return on equity if we select the 90-10 sharing ratio, before additional sharing with customers is required. For the PGA year in Oregon beginning on November 1, 2008, we have selected an 80-20 sharing ratio. Under our prior Oregon PGA mechanism, we were authorized to retain all of our earnings up to a threshold level equal to our authorized return on equity of 10.2 percent plus 300 basis points. Under both the prior and the new sharing mechanism, if earnings exceed the threshold, then 33 percent would be deferred for future refund to customers. The earnings threshold is currently subject to adjustment up or down each year depending on movements in long-term interest rates.

For 2007, the threshold after adjustment was 13.40 percent. Based on our 2007 filed earnings report, the OPUC determined that we did not exceed this threshold. Therefore, no amounts were deferred for refund to customers.

There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual purchased gas costs and pass that difference through to customers as an adjustment to future rates.

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer and seek recovery of unreimbursed environmental costs associated with certain named sites including those described in Note 11. Beginning in 2006, the OPUC authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, this authorization has been extended through January 25, 2009. We expect to file for another extension in January 2009. See Note 11.

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. Elements of these plans include:

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

We filed our IRP with the OPUC and WUTC in April 2008. On October 9, 2008, we received notification from the WUTC that as a whole the IRP meets the requirements of the Washington Administrative Code. We anticipate an order from the OPUC in the fourth quarter of 2008 or the first quarter of 2009. Although an OPUC or WUTC order acknowledging the IRP does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC and WUTC generally indicate that they would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans.

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

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In March 2008, the OPUC and WUTC approved our request to waive certain maintenance activities in connection with our investigation of some potentially defective valves. During the third quarter of 2008, we completed our investigation and the significant majority of valves susceptible to failure have been remediated. We expect to complete our remediation plan on the remaining valves by the middle of 2009. We are requesting recovery of remediation costs, estimated at approximately $0.8 million, related to these valves in Oregon through an extension of our pipeline integrity cost recovery mechanism.

Distribution Integrity Management Program. On June 25, 2008, the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Notice of Proposed Rulemaking for the Distribution Integrity Management Program (DIMP) Rule. The DIMP Rule would require operators of natural gas distribution pipeline systems to develop and implement integrity management programs for the distribution infrastructure, similar to the transmission integrity management requirements as described above. PHMSA is expected to finalize the DIMP Rule by the middle of 2009. If approved, we expect to seek approval for deferral accounting treatment and recovery of these costs in future rates from the OPUC.

Washington General Rate Case. On October 21, 2008, we filed an all-party stipulation agreement with the WUTC regarding our general rate case that was filed on March 28, 2008. The stipulation requires the approval of the WUTC. As part of the stipulation, we would be allowed a return on equity of 10.1 percent and a rate of return of 8.4 percent. Implementation of these new rates, if approved by the WUTC, would begin on January 1, 2009. Our annual revenue requirements would increase by approximately $2.7 million, or 3 percent. Although we agreed not to file another general rate case in Washington before January 2010, the parties agreed that we may file separately for a decoupling mechanism upon completion of a trial program currently being conducted by another utility in Washington.

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

Business Segments - Utility Operations

Our utility results are affected by, among other things, customer growth and changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff that contributes to changes in margin based on changes in residential and commercial customer consumption, and we have a weather normalization mechanism that adjusts customer bills up or down based on the estimated margin impact from above- or below-average temperatures during the winter heating season (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2007 Form 10-K). Both mechanisms are designed to reduce the volatility of our utility earnings.

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

Utility operations resulted in a net loss of $12.3 million, or 47 cents per share, in the third quarter of 2008 compared to a net loss of $8.6 million, or 32 cents per share, in 2007. Results from utility operations typically reflect a net loss during the third quarter because of the reduced use of natural gas during the summer. The most significant factors contributing to the increased loss compared to the third quarter of 2007 were losses from our regulatory share of higher gas costs and reduced revenue from the regulatory adjustment for income taxes paid. Also, warmer weather in the third quarter of 2008, partially offset by customer growth, contributed to lower volumes and lower margins from our residential and commercial sectors. Although volumes delivered to industrial customers increased slightly in the third quarter of 2008, margin decreased. Total utility volumes sold and delivered in the third quarter of this year increased by less than 1 percent over last year, while total utility margin decreased by 12 percent primarily due to a $2.0 million reduction from our regulatory share of gas costs and a $3.3 million reduction in our regulatory adjustment for income taxes paid (see Regulatory Adjustment for Income Taxes Paid, below).

Nine months ended September 30, 2008 compared to September 30, 2007:

In the nine months of 2008, utility operations contributed net income of $27.4 million, or $1.03 per share, compared to $37.4 million, or $1.38 per share in 2007. Total volumes increased in the nine months ended September 30, 2008 primarily due to weather that was 9 percent colder than 2007 and residential and commercial customer growth, which slowed but remained relatively strong with a net increase of 15,503 customers, or 2.4 percent, since September 30, 2007. Our annual customer growth rate remains above the national average for local gas distribution companies, despite recent economic conditions that have slowed the level of new construction in our service territory. Margin decreased in the first nine months of this year, driven by a $7.5 million loss from our regulatory share of higher gas costs compared to a $10.8 million gain from our share of significant gas cost savings last year (see Cost of Gas Sold, below).

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

Thousands, except degree day and customer data	Three months ended September 30, 2008	2007	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	29,230	28,715	515
Commercial sales	26,127	27,067	(940)
Industrial - firm sales	9,699	11,206	(1,507)
Industrial - firm transportation	43,475	39,116	4,359
Industrial - interruptible sales	18,594	19,053	(459)
Industrial - interruptible transportation	58,224	59,808	(1,584)
Total utility volumes sold and delivered	185,349	184,965	384
Utility operating revenues - dollars:			
Residential sales	$ 45,668	$ 48,345	$ (2,677)
Commercial sales	30,478	35,045	(4,567)
Industrial - firm sales	9,490	12,190	(2,700)
Industrial - firm transportation	1,512	1,439	73
Industrial - interruptible sales	14,529	16,427	(1,898)
Industrial - interruptible transportation	1,938	1,990	(52)
Regulatory adjustment for income taxes (1)	1,003	4,313	(3,310)
Other revenues	785	(500)	1,285
Total utility operating revenues	105,403	119,249	(13,846)
Cost of gas sold	63,363	71,554	8,191
Revenue taxes	2,763	3,012	249
Utility margin	$ 39,277	$ 44,683	$ (5,406)
Utility margin: (2)			
Residential sales	$ 22,381	$ 22,413	$ (32)
Commercial sales	10,059	10,750	(691)
Industrial - sales and transportation	6,758	7,203	(445)
Miscellaneous revenues	979	1,006	(27)
Gain (loss) from gas cost incentive sharing	(1,754)	203	(1,957)
Other margin adjustments	391	408	(17)
Margin before regulatory adjustments	38,814	41,983	(3,169)
Weather normalization mechanism			
Decoupling mechanism	(540)	(1,613)	1,073
Regulatory adjustment for income taxes (1)	1,003	4,313	(3,310)
Utility margin	$ 39,277	$ 44,683	$ (5,406)
Customers - end of period:			
Residential customers	592,419	578,362	14,057
Commercial customers	61,607	60,170	1,437
Industrial customers	939	930	9
Total number of customers - end of period	654,965	639,462	15,503

Actual degree days	77	123
Percent colder (warmer) than average [3]	(25%)	21%

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Thousands, except degree day data	Nine months ended September 30, 2008	2007	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	290,042	251,896	38,146
Commercial sales	185,244	166,441	18,803
Industrial - firm sales	34,797	38,815	(4,018)
Industrial - firm transportation	134,329	118,504	15,825
Industrial - interruptible sales	66,435	65,477	958
Industrial - interruptible transportation	186,390	190,723	(4,333)
Total utility volumes sold and delivered	897,237	831,856	65,381
Utility operating revenues - dollars:			
Residential sales	$ 367,011	$ 361,589	$ 5,422
Commercial sales	198,827	203,895	(5,068)
Industrial - firm sales	32,843	40,985	(8,142)
Industrial - firm transportation	4,741	4,407	334
Industrial - interruptible sales	50,221	56,153	(5,932)
Industrial - interruptible transportation	5,969	6,110	(141)
Regulatory adjustment for income taxes (1)	1,385	4,313	(2,928)
Other revenues	12,907	10,666	2,241
Total utility operating revenues	673,904	688,118	(14,214)
Cost of gas sold	433,279	431,748	(1,531)
Revenue taxes	16,786	17,013	227
Utility margin	$ 223,839	$ 239,357	$ (15,518)
Utility margin: (2)			
Residential sales	$ 154,301	$ 139,653	$ 14,648
Commercial sales	63,406	58,092	5,314
Industrial - sales and transportation	22,143	23,063	(920)
Miscellaneous revenues	4,187	3,986	201
Gain (loss) from gas cost incentive sharing	(7,548)	10,839	(18,387)
Other margin adjustments	720	634	86
Margin before regulatory adjustments	237,209	236,267	942
Weather normalization mechanism	(13,732)	(1,454)	(12,278)
Decoupling mechanism	(1,023)	231	(1,254)
Regulatory adjustment for income taxes (1)	1,385	4,313	(2,928)
Utility margin	$ 223,839	$ 239,357	$ (15,518)
Actual degree days	2,917	2,673	
Percent colder (warmer) than average (3)	9%	1%	

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

(2) Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.

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

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Residential and Commercial Sales

Our residential and commercial sales are impacted by seasonal weather patterns, energy prices, new residential construction, 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 our weather normalization mechanism in Oregon where about 90 percent of our customers are served. This mechanism does not cover industrial customers or the approximately 9 percent of our Oregon residential and commercial customers who have opted out of the mechanism. The weather normalization mechanism is applied to Oregon residential and commercial customers bills from December 1 through May 15 and therefore has no effect during the third quarter. We also have a conservation decoupling mechanism in Oregon 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 residential and commercial customers are served, we currently do not have a weather normalization or a conservation decoupling mechanism. As a result, we are not fully insulated from earnings volatility due to weather and conservation. See the tables above for the adjustments to utility margin revenues from the weather normalization and decoupling mechanisms for the three and nine months ended September 30, 2008 and 2007.

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

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

- 1 percent lower sales volumes and 9 percent lower operating revenues as a result of lower billing rates in 2008, which primarily reflect an 8 to 10 percent decrease in gas costs set in the PGA effective November 1, 2007; and

- customer growth of 2.4 percent.

Nine months ended September 30, 2008 compared to September 30, 2007:

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

- 14 percent higher sales volumes as a result of 2.4 percent customer growth and weather that was 9 percent colder than last year; and

- operating revenues that were flat due to lower billing rates, which reflect an 8 to 10 percent decrease in gas costs set in the PGA effective November 1, 2007 offset by the higher volumes referred to above (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2007 Form 10-K).

Utility operating revenues include accruals for unbilled revenues (gas delivered but not yet billed to customers) based on estimates of gas deliveries from that month s meter reading dates to month end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenues at the end of each month. At September 30, 2008, accrued unbilled revenue was $16.6 million, compared to $20.9 million at September 30, 2007, with the decrease reflecting lower billing rates and warmer weather toward the end of the third quarter of 2008 as compared to 2007.

Industrial Sales and Transportation

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

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

Total volumes delivered to industrial sales and transportation customers increased 0.8 million therms, or less than 1 percent, in the third quarter of 2008 compared to the same period in 2007. Industrial margins were down by $0.4 million, or 6 percent, over last year. The increase in volume was primarily due to additional load from a new large volume customer, which is billed at a lower margin rate. This increase in volume was partially offset by higher margin customers that reduced their usage due to the current economic environment. We expect this portion of our industrial customer base will continue to be challenged by high energy prices and the slowing economy.

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Nine months ended September 30, 2008 compared to September 30, 2007:

Total volumes delivered to industrial sales and transportation customers increased 8.4 million therms, or 2 percent, in the first nine months of 2008 as compared to the same period in 2007. Utility margin related to these customers was down $0.9 million, or 4 percent, over last year, primarily due to some customers moving to lower margin rate schedules and prolonged customer cutbacks and shut-downs due to higher gas costs, as discussed above.

Regulatory Adjustment for Income Taxes Paid

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

As described above under Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, gas costs above those set in our PGA incentive gas cost sharing mechanism may cause us to recognize additional expense, and consequently affect the amount of income tax we actually pay. Based on our operating results through September 30, 2008, we have recorded an estimated refund to customers of $0.3 million for the 2008 tax year. However, a net surcharge totaling $0.9 million was included in margin for the nine months ended September 30, 2008, reflecting the current year s estimated accrual plus a true-up adjustment of $1.2 million for our surcharges related to the 2006 and 2007 tax years. Our tax report for the 2007 tax year, which was filed on October 15, 2008, reflected an estimated surcharge of $5.5 million. Our tax report for the 2008 tax year is due by October 15, 2009. Each of these reports is subject to review by the OPUC, which is required to issue final orders on these tax reports by April 1 of the year following the filing, with rate adjustments effective as of the following June 1.

Other Revenues

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

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

Other revenues were $0.8 million in the third quarter of 2008, an increase of $1.3 million over the third quarter of 2007, with the increase primarily due to a net increase in the decoupling regulatory deferral and amortization.

Nine months ended September 30, 2008 compared to September 30, 2007:

Other revenues were $12.9 million in the first nine months of 2008, an increase of $2.2 million over the same period in 2007, with the increase primarily due to an increase in the interstate storage credit compared to 2007.

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Cost of Gas Sold

The cost of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use. Our regulated utility does not generally earn a profit or incur a loss on gas commodity purchases. The OPUC and the WUTC require the natural gas commodity cost to be billed to customers at the same cost incurred or expected to be incurred by the utility. However, under the PGA mechanism in Oregon, our net income is affected by differences between actual and expected purchased gas costs primarily due to market fluctuation and volatility affecting unhedged purchases (see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, above). We use natural gas derivatives, primarily fixed-price commodity swaps, under the terms of our Financial Derivatives Policy to help manage our exposure to rising gas prices. Gains and losses from financial hedge contracts are generally included in our PGA prices and normally do not impact net income as the hedges are usually 100 percent passed through to customers in annual rate changes. However, utility gas hedges entered into after the annual PGA filing in Oregon may impact net income to the degree of our share of any gain or loss under the PGA. In Washington, 100 percent of the actual gas costs, including hedge gains and losses, are passed through in customer rates (see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, and Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2007 Form 10-K, and Note 10).

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

- total cost of gas sold decreased $8.2 million or 11 percent in 2008 compared to 2007;
- the average cost of gas sold decreased 8 percent from 83 cents per therm in 2007 to 76 cents in 2008, primarily reflecting our 8 to 10 percent PGA rate decrease effective November 1, 2007; and
- net gains of $2.1 million were realized from our financial hedges, compared to $15.5 million of net losses in the same period of 2007.

Nine months ended September 30, 2008 compared to September 30, 2007:

- total cost of gas sold increased $1.5 million or less than 1 percent in 2008 compared to 2007;
- the average cost of gas sold decreased 10 percent from 83 cents per therm in 2007 to 75 cents in 2008, primarily reflecting our 8 to 10 percent PGA rate decrease effective November 1, 2007; and
- net gains of $23.4 million were realized from our financial hedges, compared to $25.6 million of net losses in the same period of 2007.

In the first nine months of 2008, our actual gas costs were higher than the gas costs embedded in rates, while during the first nine months of 2007 our actual gas costs were significantly lower than gas costs embedded in rates. The effect on shareholders was a margin gain of $10.8 million in the first nine months of 2007, compared to a margin loss of $7.5 million during the first nine months of 2008.

Business Segments Other than Utility Operations

Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility, asset optimization and our wholly-owned subsidiary, Gill Ranch. We earned $1.9 million and $6.8 million in net income from our gas storage business segment in the three and nine months ended September 30, 2008, respectively, after regulatory sharing and income taxes, which is equivalent to 8 cents and 26 cents per share, respectively. This compares to net income of $2.5 million and $7.0 million, or 9 cents and 26 cents per share, in the three and nine months ended September 30, 2007, respectively. The decrease in the three and nine months ended September 30, 2008 was primarily due to higher depreciation and interest expense related to capital improvements at our Mist storage facility and costs related to Gill Ranch development, offset in part by higher net operating revenues from storage services in the nine months ended September 30, 2008 (see Part II, Item 7., Results of Operations Business Segments Other Than Local Gas Distribution Gas Storage, in the 2007 Form 10-K).

In Oregon, we retain 80 percent of the pre-tax income from gas storage services as well as from third party optimization revenues when the costs of the capacity are not included in utility rates, or 33 percent of the pre-tax income from such storage and optimization when the capacity costs are 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 gas storage services and third-party optimization.

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

Other

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

Net income from the other business segment for the three and nine months ended September 30, 2008 was $0.3 million and $2.1 million, respectively, compared to $0.2 million and $0.4 million for the three and nine months ended September 30, 2007, respectively. The increase in net income in the nine months ended September 30, 2008 reflects the gain on the sale of our investment in a Boeing 737-300 aircraft (see Note 2).

Consolidated Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the third quarter of 2008 were $27.4 million compared to $27.1 million in 2007, an increase of $0.3 million or 1 percent. The increase was largely due to higher payroll expense, increased customer service costs, higher injury and damage claims and compressor repair expenses, partially offset by lower incentive compensation accruals in 2008 compared to 2007. Operations and maintenance expenses in the third quarter of 2007 also included certain increases for strategic initiatives, which management approved based on a significant contribution to earnings from regulatory sharing of gas cost savings during the 2007 fiscal year

During the first nine months of 2008, operations and maintenance expenses were $81.7 million compared to $84.4 million in 2007, a decrease of $2.7 million or 3 percent. The decrease was primarily driven by a reduction in 2008 incentive compensation accruals and higher costs in 2007 for certain strategic initiatives noted above, which were partially offset by higher payroll expense, increased costs associated with serving our growing customer base, higher gas storage operating expenses and higher legal expenses.

Our utility bad debt expense for the 12 months ended September 30, 2008 was $3.2 million or 0.31 percent of total utility operating revenues, as compared to $2.8 million or 0.27 percent for the same period a year ago. Over the last three years, our bad debt expense ratio remained fairly steady near 0.30 percent of revenues, which is low by industry standards. With a weaker economy and the increase in customer rates from the higher cost of natural gas, it may be more difficult for our customers to pay their bills. Under the PGA mechanism, we are allowed to adjust our rates to customers each year to recover the expected increase in bad debt expense due to the higher cost of natural gas. The revenue adjustment for bad debt expense is based on our average write-off rate over the last three years multiplied by the estimated increase in commodity costs. Although we may experience an increase in bad debt expense over the next 12 months, we believe much of the increase will be offset by the allowed increase in revenues under the PGA mechanism.

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, decreased $0.7 million, or 10 percent, in the three months ended September 30, 2008 over the same period in 2007, and increased $1.0 million, or 5 percent, in the first nine months of 2008 compared to 2007. Regulatory fees decreased $0.7 million in the third quarter of 2008 compared to the third quarter of 2007. Property taxes increased $1.3 million in the first nine months of 2008 compared to 2007 due to increased utility and non-utility plant in service and increased gas inventories.

We have been involved in litigation with the Oregon Department of Revenue (ODOR) over whether natural gas inventories and appliance inventories held for resale are required to be taxed as personal property. In November 2007, the Oregon Tax Court (Tax Court) ruled in our favor stating that these inventories were exempt from property tax. However, the ODOR appealed the judgment to the Oregon Supreme Court in August 2008. If we are successful in this litigation, we would be entitled to a refund of over $3.0 million for property taxes paid on inventories beginning with the 2002-2003 tax year, plus accrued interest. Due to the uncertain outcome of the proceeding, we have not recorded an adjustment to the financial statements to recognize the potential gain contingency.

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Depreciation and Amortization

Depreciation and amortization expense increased by $0.9 million, or 5 percent, and by $2.8 million, or 6 percent, in the three and nine months ended September 30, 2008, respectively, compared to the same periods in 2007. The increased expense reflects ongoing capital expenditures for utility and non-utility plant that were made primarily to meet continuing customer growth, to upgrade utility operating facilities and to expand non-utility storage capacity.

In 2007, we completed a depreciation study on all utility plant, property and equipment. The result of the depreciation study concluded that our depreciation rates should be reduced to reflect asset lives that are longer than previously estimated. Under regulatory requirements, these new depreciation rates must be approved before they can be put into effect. In Oregon, we submitted the depreciation study for regulatory approval in 2007, and we expect to receive approval from the OPUC before the end of 2008, with implementation of the new rates beginning in 2009. In Washington, the depreciation study was submitted as part of our general rate case filed in March 2008. We expect to receive approval of the new rates from the WUTC before the end of 2008, with implementation of the new rates beginning on January 1, 2009 (see Results of Operations Regulatory Matters Rate Mechanisms Washington General Rate Case, above). In the Oregon depreciation filing and the Washington rate case, we also included a request to adjust our amortization rate on the regulatory flow-through amount for taxes. We expect a net decrease in cash flow of between $5 million to $10 million annually due to the new depreciation rates and the new tax flow-through amortization rates, but we do not expect a material impact on our financial condition or results of operations.

Other Income and Expense Net

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

Thousands	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Other income and expense - net:				
Gains from company-owned life insurance	$ 459	$ 605	$ 1,437	$ 1,510
Interest income	28	57	158	421
Other non-operating income (expense)	(38)	(414)	1,359	(1,603)
Net interest income (expense) on deferred regulatory accounts	217	512	(126)	291
Gain (loss) from equity investments	(25)	(24)	(74)	174
Total other income and expense - net	$ 641	$ 736	$ 2,754	$ 793

In the three months ended September 30, 2008, other income and expense net decreased $0.1 million compared to the same period in 2007. In the nine months ended September 30, 2008, other income and expense net increased $2.0 million compared to the same period in 2007, primarily due to the sale of our investment in a Boeing 737-300 aircraft in the second quarter of 2008.

Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized decreased $0.1 million, or 1 percent, and decreased $0.1 million, or less than 1 percent, in the three and nine months ended September 30, 2008, respectively, compared to the same periods in 2007.

Income Tax Expense

Income tax expense totaled $21.2 million in the nine months ended September 30, 2008 compared to $26.2 million in the nine months ended September 30, 2007. The effective tax rate was 36.8 percent in 2008 compared to 36.9 percent in 2007. The lower income tax expense in 2008 is due primarily to lower pre-tax book income.

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Financial Condition

Capital Structure

Our goal is to maintain a target capital structure comprised of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources also are used to meet long-term debt redemption requirements and short-term commercial paper maturities (see Liquidity and Capital Resources, below). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at September 30, 2008 and 2007 and at December 31, 2007, including short-term debt, was as follows:

	Sept. 30, 2008	Sept. 30, 2007	Dec. 31, 2007
Common stock equity	46.8%	48.2%	47.4%
Long-term debt	39.7%	42.2%	40.8%
Short-term debt, including current maturities of long-term debt	13.5%	9.6%	11.8%
Total	100.0%	100.0%	100.0%

We have a common stock share repurchase program with Board authorization to purchase up to an aggregate of 2.8 million shares, or up to $100 million in value. Purchases under this program are made in the open market or through privately negotiated transactions. See Financing Activities, below, and Part II, Item 2., Unregistered Sales of Equity Securities and Use of Proceeds, below.

Liquidity and Capital Resources

At September 30, 2008, we had $4.1 million of cash and cash equivalents compared to $4.6 million at September 30, 2007 and $6.1 million at December 31, 2007. Short-term liquidity is provided by cash balances, cash flow from operations and proceeds from the sale of commercial paper notes, which are supported by an unsecured $250 million credit facility (see Credit Agreement, below). We use long-term debt proceeds to finance capital expenditures and refinance maturing short-term or long-term debt.

Our senior long-term debt ratings are AA- and A2 from Standard and Poor s Corporation (S&P) and Moody s Investor Services, Inc. (Moody s), respectively, while our short-term debt ratings are A-1+ and P-1 from S&P and Moody s, respectively. The credit markets, including the commercial paper market, have experienced significant volatility and adverse conditions in recent months, as reflected by increased credit spreads and limited access to capital markets for new financings. If these adverse market conditions continue, we may be affected by increased borrowing costs associated with commercial paper and other debt financing. However, with our current debt ratings we have been able to issue commercial paper notes at attractive rates and have not had to borrow from our $250 million back-up credit facility. In addition to having met our liquidity requirements by issuing commercial paper, we also decided recently to carry higher cash balances to maintain liquidity while market conditions remain uncertain. We took this step to provide additional liquidity until market conditions improve. In the event that we are not able to issue commercial paper or other debt instruments due to market conditions, we expect that our liquidity needs can be met by using cash balances or drawing upon our committed credit facility (see Credit Agreement, below). We also have a universal shelf registration statement filed with the Securities and Exchange Commission for the issuance of secured and unsecured debt or equity securities.

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

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Neither our Mortgage and Deed of Trust nor the indenture under which our 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.

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, 2007, our future contractual obligations have increased by a net of $40 million as follows:

- an increase of $22 million in connection with an approved automated meter reading project; and
- an increase of $18 million related to equipment purchases in connection with the development of Gill Ranch.

Contractual obligations at December 31, 2007 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2007 Form 10-K.

Commercial Paper

Our primary source of short-term liquidity 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 inventories 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 an unsecured revolving credit facility (see Credit Agreement, below, and Part II, Item 8., Note 6, in the 2007 Form 10-K). Our commercial paper program did not experience any liquidity disruptions as a result of the recent credit problems that affected asset-backed commercial paper programs and certain other issuers of commercial paper. At September 30, 2008, September 30, 2007 and December 31, 2007, we had commercial paper outstanding of $174.8 million, $112.1 million and $143.1 million, respectively, and the weighted-average borrowing rate was 2.36 percent, 5.01 percent and 4.41 percent, respectively. This year s outstanding balances were higher than last year primarily due to the higher gas costs and the corresponding refund of PGA deferrals discussed above in Results of Operations Comparison of Utility Operations Cost of Gas Sold.

Credit Agreement

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

Lender Rating	**Amount Committed (in $000 s)**
AAA/Aaa	$ 40,000
AA/Aa	190,000
A/A	20,000
BBB/Baa	
Total	$ 250,000

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

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Pursuant to the terms of our credit agreement, we may extend commitments for additional one-year periods subject to lender approval. We extended commitments with six of the seven lenders under the credit agreement, with commitments totaling $210 million to May 31, 2013. The credit agreement also allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million, and to replace any lenders who decline to extend the terms of the credit agreement. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. Any principal and unpaid interest owed on borrowings under the credit agreement are due and payable on or before the expiration date, which is May 31, 2013 for all except one lender, which has a commitment amount totaling $40 million that would be due and payable on or before May 31, 2012. There were no outstanding balances under this credit agreement at September 30, 2008 and 2007 or December 31, 2007. The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at September 30, 2008 and 2007 and December 31, 2007 with consolidated indebtedness to total capitalization ratios of 53 percent, 52 percent, and 53 percent, respectively. For additional information regarding our credit agreement, see Part II, Item 7., Financial Condition Credit Agreement, in the 2007 Form 10-K.

Credit Ratings

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

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

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

Redemptions of Long-Term Debt

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

Thousands	Nine months ended September 30, 2008	Nine months ended September 30, 2007	Year ended Dec. 31, 2007
Medium-Term Notes			
6.31% Series B due 2007	$	$ 20,000	$ 20,000
6.80% Series B due 2007		9,500	9,500
6.50% Series B due 2008	5,000		
	$ 5,000	$ 29,500	$ 29,500

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, gas prices, deferred income taxes, changes in working capital requirements, regulatory deferrals and other cash and non-cash adjustments to operating results. The overall change in cash flow from operating activities for the nine months ended September 30, 2008 compared to the same period in 2007 was a decrease of $88.7 million. The major factors contributing to the cash flow changes in the first nine months of 2008 compared to the first nine months of 2007 are as follows:

a decrease of $8.4 million in net income;

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an increase of $10.9 million in deferred income taxes, primarily due to the Economic Stimulus Act of 2008 (the Stimulus Act) (for further information see the paragraph below);

a decrease of $69.0 million in deferred gas costs, primarily related to the refunding of prior year s gas cost savings and the accumulation of current year s cost deferrals from higher gas prices compared to our weighted-average cost of gas;

a decrease of $12.3 million resulting from a smaller decrease in accounts receivable and accrued unbilled revenue due to lower balances at year end 2007 compared to the prior year;

a decrease of $12.0 million resulting from higher cost of gas injected into storage inventories during the summer for withdrawal during the winter heating season, reflecting a sharp increase in gas prices in June and July of 2008 compared to 2007;

a decrease of $11.7 million resulting from a larger decrease in accounts payable due to higher balances at year end 2007 compared to the prior year; and

an increase of $30.7 million from lower income tax payments.

The Stimulus Act enacted on February 13, 2008, allows an additional first-year tax deduction for depreciation equal to 50 percent of the adjusted basis of qualified property. The extra 50 percent depreciation deduction in the first year is an acceleration of tax depreciation deductions that otherwise would have been taken in the later years of an asset s recovery period. In general, the extra 50 percent depreciation deduction is available for most personal property acquired and placed in service after December 31, 2007 and generally before January 1, 2009. We anticipate an estimated $13 million increase in cash flow from reduced income taxes based on actual and projected plant investments between January 1, 2008 and December 31, 2008.

Investing Activities

Cash requirements for investing activities in the first nine months of 2008 totaled $75.2 million, down from $83.5 million in the same period of 2007. Investments in utility plant totaled $66.8 million in the first nine months of 2008, compared to the $65.3 million expended in the same period of 2007.

Investments in non-utility property during the first nine months of 2008 totaled $5.8 million, down from $18.3 million during the first nine months of 2007, primarily due to expansion at our Mist gas storage facilities in 2007.

Cash used in other investing activities during the first nine months of 2008 totaled $2.6 million, down from an increase in cash of $0.1 million during the first nine months of 2007. The decrease in 2008 is primarily due to $6.8 million of proceeds received from the sale of our investment in a Boeing 737-300 aircraft and $0.7 million of proceeds received from the sale of utility property in Albany, Oregon, which was offset by a $5.3 million investment in the Palomar project and a $5.0 million restricted cash investment in Gill Ranch.

Our utility capital expenditures are expected to total about $105 million in 2008, including amounts for the completion of a new automated meter reading project. In addition, we expect to spend approximately $15 to $20 million for non-utility capital expenditures for the Gill Ranch and Palomar projects in 2008. The planning and permitting phase of the Palomar project is expected to continue through the first quarter of 2010, and we have revised our estimated capital cost to be between $40 million and $45 million, 50 percent of which would be contributed by us.

In this economic environment we continue to review our capital expenditures, but at this time we have not revised our estimate of utility construction expenditures over the five-year period 2008 through 2012 of between $500 and $600 million, as previously reported (see Part II, Item 7., Financial Condition Cash Flows Investing Activities, in the 2007 Form 10-K).

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Financing Activities

Cash provided by financing activities in the first nine months of 2008 totaled $1.2 million, up from $78.3 million cash used in the same period of 2007. Short-term debt balances increased by $31.7 million in the first nine months of 2008 compared to an increase of $12.0 million in 2007. Under our common stock repurchase program, no shares were purchased in 2008 compared to 744,428 shares purchased at a total cost of $34.4 million in the first nine months of 2007. In the first nine months of 2008, we redeemed $5.0 million of long-term debt, compared to $29.5 million of long-term debt in the first nine months of 2007.

Pension Funding Status

Our policy is to fund the qualified defined benefit pension plans, as needed, based on tax regulations and funding requirements under federal law, including funding the amounts required by the Employee Retirement Income Security Act of 1974. In addition, it is our intent to contribute sufficient amounts as needed on an actuarial basis to maintain funding targets and to provide for the timely payment of future benefits under these plans. We did not make and were not required to make a cash contribution to our qualified defined benefit pension plans in 2008. Our qualified defined benefit pension plans were funded at nearly 100 percent of the projected benefit obligation at December 31, 2007. However, we expect our funded status to be lower at December 31, 2008 due to declines in the market value of plan assets during 2008, but the asset value decline may be partially offset by a decrease in projected benefit obligations due to higher discount rates used in measuring plan liabilities. The net impact in funded status may result in increased pension expense in 2009 and higher future contributions than previously disclosed in our 2007 Form 10-K.

For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Part II, Item 7., Financial Condition Pension Cost and Funding Status of Qualified Retirement Plans, and Part II, Item 8., Note 7, Pension and Other Postretirement Benefits, in the 2007 Form 10-K.

Ratios of Earnings to Fixed Charges

For the nine and twelve months ended September 30, 2008 our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 2.96 and 3.64, respectively. For the nine, and twelve months ended September 30, 2007 our ratios of earnings to fixed charges were 3.35 and 3.80, respectively. For the twelve months ended December 31, 2007, our ratio of earnings to fixed charges was 3.92. For this purpose, earnings consist of net income before taxes plus fixed charges. Fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. Because a significant part of our business is of a seasonal nature, the ratios for the interim periods are not necessarily indicative of the results for a full year.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, Accounting for Contingencies (see Part II, Item 7., Application of Critical Accounting Policies and Estimates, in the 2007 Form 10-K). At September 30, 2008, we had a regulatory asset relating to environmental accruals of $64.7 million, which includes $28.3 million of total paid expenditures to date, $31.0 million for additional environmental costs expected to be paid in the future and accrued interest of $5.4 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 11.

Forward-Looking Statements

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

prevailing state and federal governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, timely and adequate purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in laws and regulations including but not limited to tax laws and policies, changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity, including regulatory allowance or disallowance of costs based on regulatory prudency reviews;

economic factors that could cause a severe downturn in the national economy, in particular the economies of Oregon and Washington, thus affecting demand for natural gas;

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

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

weather conditions, natural phenomena, including earthquakes or other geohazard events, and other pandemic 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 and our ability to remain price competitive;

the creditworthiness of customers, suppliers and financial derivative counterparties;

our ability to access sufficient gas supplies and our dependence on a single pipeline transportation provider for natural gas transmission;

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

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

unanticipated changes that may affect our liquidity or access to capital markets, including the credit environment or financial services sector;

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;

unanticipated changes in operating expenses and capital expenditures;

changes in estimates of potential liabilities relating to environmental contingencies or in timely and adequate regulatory or insurance recovery for such liabilities;

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

capital market conditions, including their effect on financing costs, 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 the timing of such projects; and

legal and administrative proceedings and settlements.

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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.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price risk, interest rate risk, foreign currency risk, credit risk and weather risk (see Part II, Item 7A. in the 2007 Form 10-K, and Part II, Item 1A., Risk Factors, below). The following are updates to certain of these market risks:

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion, potential market speculation and other factors that affect short-term supply and demand. Commodity-price financial swap and option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed or capped prices. These financial hedge contracts are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. At September 30, 2008 and 2007, notional amounts under these financial hedge contracts totaled $460.4 million and $357.8 million, respectively. If all of the commodity-based financial hedge contracts had been settled on September 30, 2008, a loss of about $111.0 million would have been realized and recorded to a deferred regulatory account (see Note 10). We monitor the liquidity of our financial hedge contracts. Based on the existing open interest in the contracts held we believe existing contracts to be liquid. All of our financial hedge contracts settle by or are extendible to October 31, 2010. The $111.0 million unrealized loss is an estimate of future cash flows based on forward market prices that are expected to be paid as follows: $103.3 million in the next 12 month contract period and $7.7 million between the next 12 and 24 month contract period. The amount realized will change based on market prices at the time contract settlements are fixed.

Natural gas commodity prices early in the third quarter were higher than prices embedded in our current PGA for unhedged purchases. To the extent that we purchase gas at prices above those embedded in rates for current customer consumption (i.e. not for storage injections), our earnings are negatively impacted because, under our PGA mechanism in effect prior to November 1, 2008, 33 percent of any difference between the actual purchase gas costs and the embedded gas costs in rates to Oregon customers are recognized in current income. A new PGA mechanism was approved in Oregon, effective in rates on November 1, 2008 (for further information see Results of Operations Regulatory Matters Rate Mechanism Purchased Gas Adjustment, above). In the third quarter of 2008, we recognized a loss of $1.8 million due to higher prices.

Credit Risk

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure relating to commodity hedge contracts at September 30, 2008, reflected an amount we owed of $111.0 million to our finance derivative counterparties. Our Financial Derivatives Policy requires counterparties to have a minimum investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty s credit rating. Some counterparties were recently downgraded but continue to maintain investment grade ratings (see table below). Due to current market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require letters of credit or guarantees as circumstances warrant. Our actual derivative credit exposure, which reflects amounts that financial derivative counterparties owe to us, is under contracts that expire on or before October 31, 2009. There is minimal exposure in the second gas year to counterparties rated at least AA-/Aa3, and no exposure in the third gas year or thereafter.

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

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)		
Thousands	**Sept. 30, 2008**	**Sept. 30, 2007**	**Dec. 31, 2007**
AAA/Aaa	$ (15,421)	$ (4,206)	$ (309)
AA/Aa	(81,649)	(29,346)	(13,941)
A/A	(13,951)		123
BBB/Baa			
Total	$ (111,021)	$ (33,552)	$ (14,127)

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

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of September 30, 2008, the principal executive officer and principal financial officer of Northwest Natural Gas Company (NW Natural) have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act)). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that the disclosure controls and procedures were effective to ensure that information required to be disclosed by NW Natural and included in our reports filed or furnished under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms 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).

During the quarter ended September 30, 2008, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

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

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

Item 1A. RISK FACTORS

As a result of developments in the financial markets and energy prices since the filing of our 2007 Form 10-K, we are providing updates to the risk factors below. Other than those risk factors set forth below and in Part I, Item 3. Quantitative and Qualitative Disclosures about Market Risk, there were no material changes from the risk factors discussed in Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2007. In addition to the other information set forth in this report, you should carefully consider those risk factors which could materially affect our business, financial condition or results of operations. The risks described in the 2007 Form 10-K and in this report 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

Economic risk. *Changes in the economy and in the financial market, including our ability to access the capital markets at reasonable rates, may have a negative impact on our financial condition, results of operations and cash flows.*

Our operations are affected by local and national economic and financial market conditions. A slowdown in economic activity and higher energy prices may result in a decline in energy consumption and slower customer growth. Also, continued uncertainty in the financial markets could increase our cost of capital and affect our ability to borrow. Our business relies on access to capital markets, including the commercial paper markets, to finance our utility operations, construction expenditures and other capital expense requirements, and to refund maturing debt, that cannot be funded entirely by operating cash flows. Changes in the economy that impact our ability to access the capital markets at competitive rates may also negatively impact our ability to make strategic investments and our results of operations. We also provide pension plans and postretirement healthcare benefits to eligible full-time employees, which may be affected by changes in the economy. Sustained declines in equity markets and reductions in bond yields could have a material adverse effect on the funded status of our pension plans. In these circumstances, we may be required to recognize an increase in unfunded liability and an increase in annual pension expense. An economic slowdown coupled with higher energy prices may also impact consumer demand and business spending, result in higher debt levels, higher interest costs and higher bad debt expense, which could adversely impact our financial condition, results of operations or cash flows.

Gas price risk. *Higher natural gas commodity prices and fluctuations in the price of gas may adversely affect our cash flows and earnings.*

In recent years, natural gas commodity prices have been volatile, primarily due to growing demand, especially for power generation, and stagnant North American gas production. The cost we pay for natural gas is passed through to our customers through an annual PGA rate adjustment in Oregon and Washington (see below). Significant increases in the commodity price of natural gas may raise the cost of energy to our existing customers, thereby causing those customers to conserve or switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select alternative sources of energy. Decreases in the volume of gas we sell could reduce our earnings in the absence of decoupled rate structures, and a decline in customers could slow growth in our future earnings.

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Future increases in the price of natural gas may also cause us to experience a significant increase in short-term debt because we pay suppliers for gas when it is purchased, which can be materially in advance of when these costs are recovered due to carrying of storage inventory and the potential lag in collections of customer bills for gas delivered. Significant increases in the price of gas can also slow our collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater expense associated with collection efforts and increased bad debt expense.

In Oregon and in Washington, the utility has PGA tariffs which provide for annual revisions in rates resulting from changes in the cost of purchased gas. In Oregon, we also have a price-elasticity adjustment that adjusts rates through the annual PGA for expected increases or decreases in customer usage due to higher or lower gas prices. The Oregon PGA tariff also provides that a percentage, set annually, of any difference between the actual purchased gas costs and the actual recoveries of gas costs in rates be recognized as current income or expense (see Part I, Item 2., Results of Operations Regulatory Matters Rate Mechanisms). Accordingly, higher gas costs than those assumed in setting rates can adversely affect our operating cash flow, liquidity and results of operations, until such costs are recovered from customers. Notwithstanding our current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce rates, which also could adversely affect our results of operations.

We use natural gas derivatives, primarily fixed-price commodity swaps to help manage our exposure to rising gas prices. Gains and losses from financial hedge contracts are generally included in our PGA prices and normally do not impact net income as the hedges are usually 100 percent passed through to customers in annual rate changes, subject to a regulatory prudency review. However, we may not be able to completely offset the price risk associated with volatile gas prices which could lead to volatility in our earnings.

Business Development Risk. *The development, construction, startup and operation of our business development projects may involve unanticipated changes or delays that could negatively impact our financial condition and results of operations, and investing in business development projects through partnerships or joint ventures may affect our ability to manage risks.*

Business development projects involve many risks. We are in the early development stages on two strategic business development projects: the Gill Ranch gas storage facility in California, and the Palomar gas transmission pipeline in Oregon. We may not be able to obtain required governmental permits and approvals, or the financing, to complete projects in a cost-efficient or timely manner. There also may be startup and construction delays; construction cost overruns; inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts; changes in market prices; and operating cost increases. Additionally, natural gas storage and gas transportation markets are intensely competitive, both within the natural gas industry and with alternative sources of energy. To complete our business development projects, we will need to secure financing from willing lenders at reasonable interest rates. If the current tight credit markets persist, we may be unable to acquire the necessary financing to fund our business development projects at acceptable interest rates within a timeframe favorable for completing the project. Also, if we do not obtain the necessary regulatory approvals in a timely manner, the development projects may need to be delayed or abandoned and could have a material adverse effect on our financial condition, results of operations or cash flows.

We use joint ventures and other business arrangements for certain non-utility development projects to mitigate the risks of our projects, including Palomar and Gill Ranch, and we may acquire interests in other similar types of arrangements in the future. Under these types of business arrangements, we may not be able to fully direct the management and policies of the business relationship, and other participants in that relationship may take action contrary to our instructions or requests. In addition, other participants may withdraw from the arrangement, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours. Although we have contractual and other legal remedies to enforce our interests, if a participant in one of these business arrangements acts contrary to our rights, it could adversely impact 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 September 30, 2008 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [2]
Balance forward			2,124,528	$ 16,732,648
07/01/08 - 07/31/08	1,024	$ 45.76		
08/01/08 - 08/31/08	20,347	$ 47.31		
09/01/08 - 09/30/08	2,111	$ 49.86		
Total	23,482	$ 47.48	2,124,528	$ 16,732,648

(1) During the quarter ended September 30, 2008, 21,255 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 2,227 shares of our common stock were purchased on the open market during the quarter under equity-based programs. During the three months ended September 30, 2008, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2009 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the nine months ended September 30, 2008, no shares of our common stock were purchased pursuant to this program. Since the program s inception in 2000 we have repurchased 2.1 million shares of common stock at a total cost of $83.3 million.

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: November 5, 2008

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

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

September 30, 2008

Document	**Exhibit Number**
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