NORTHWEST NATURAL GAS CO
Form 10-Q
November 08, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 2007

OR

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

Commission File No. 1-15973

NORTHWEST NATURAL GAS COMPANY

(Exact name of registrant as specified in its charter)

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

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

(Address of principal executive offices) (Zip Code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

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

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

At October 31, 2007, 26,452,275 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

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NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended September 30, 2007

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Income

(Unaudited)

Thousands, except per share amounts	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Operating revenues:				
Gross operating revenues	$ 124,245	$ 114,914	$ 701,585	$ 676,284
Less: Cost of sales	71,570	70,634	431,783	431,069
Revenue taxes	3,012	2,939	17,013	16,663
Net operating revenues	49,663	41,341	252,789	228,552
Operating expenses:				
Operations and maintenance	27,111	25,640	84,370	81,796
General taxes	6,389	5,595	19,557	19,234
Depreciation and amortization	17,173	16,196	50,930	47,988
Total operating expenses	50,673	47,431	154,857	149,018
Income (loss) from operations	(1,010)	(6,090)	97,932	79,534
Other income and expense - net	736	314	793	1,242
Interest charges - net of amounts capitalized	9,395	9,781	27,763	28,820
Income (loss) before income taxes	(9,669)	(15,557)	70,962	51,956
Income tax expense (benefit)	(3,761)	(5,833)	26,178	18,653
Net income (loss)	$ (5,908)	$ (9,724)	$ 44,784	$ 33,303
Average common shares outstanding:				
Basic	26,609	27,556	26,945	27,568
Diluted	26,609	27,556	27,109	27,686
Earnings (loss) per share of common stock:				
Basic	$ (0.22)	$ (0.35)	$ 1.66	$ 1.21
Diluted	$ (0.22)	$ (0.35)	$ 1.65	$ 1.20

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	Sept. 30, 2007 (Unaudited)	Sept. 30, 2006 (Unaudited)	Dec. 31, 2006
Assets:			
Plant and property:			
Utility plant	$ 2,025,106	$ 1,939,673	$ 1,963,498
Less accumulated depreciation	604,957	566,972	574,093
Utility plant - net	1,420,149	1,372,701	1,389,405
Non-utility property	61,025	41,662	42,652
Less accumulated depreciation and amortization	7,637	6,684	6,916
Non-utility property - net	53,388	34,978	35,736
Total plant and property	1,473,537	1,407,679	1,425,141
Current assets:			
Cash and cash equivalents	4,642	5,685	5,767
Accounts receivable	33,328	31,791	82,070
Accrued unbilled revenue	20,886	19,316	87,548
Allowance for uncollectible accounts	(1,726)	(2,060)	(3,033)
Regulatory assets	27,979	37,519	31,509
Fair value of non-trading derivatives	1,423	10,205	5,109
Inventories:			
Gas	79,607	94,808	68,576
Materials and supplies	9,264	9,723	9,552
Income taxes receivable	15,111	12,052	
Prepayments and other current assets	14,449	44,125	21,695
Total current assets	204,963	263,164	308,793
Investments, deferred charges and other assets:			
Regulatory assets	197,333	106,286	164,771
Fair value of non-trading derivatives	950	1,955	1,448
Other investments	51,014	55,695	47,985
Other	8,304	8,781	8,718
Total investments, deferred charges and other assets	257,601	172,717	222,922
Total assets	$ 1,936,101	$ 1,843,560	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	Sept. 30, 2007 (Unaudited)	Sept. 30, 2006 (Unaudited)	Dec. 31, 2006
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 340,352	$ 383,897	$ 371,127
Earnings invested in the business	246,865	210,457	230,774
Accumulated other comprehensive income (loss)	(2,261)	(1,911)	(2,356)
Total common stock equity	584,956	592,443	599,545
Long-term debt	512,000	492,000	517,000
Total capitalization	1,096,956	1,084,443	1,116,545
Current liabilities:			
Notes payable	112,100	103,300	100,100
Long-term debt due within one year	5,000	29,500	29,500
Accounts payable	57,669	64,511	113,579
Taxes accrued	11,898	12,071	21,230
Interest accrued	11,247	11,454	2,924
Regulatory liabilities	51,481	19,005	11,919
Fair value of non-trading derivatives	27,350	32,098	38,772
Other current and accrued liabilities	22,381	16,017	21,455
Total current liabilities	299,126	287,956	339,479
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	215,981	225,792	210,084
Regulatory liabilities	206,642	187,167	202,982
Pension and other postretirement benefit liabilities	57,099	18,329	52,690
Fair value of non-trading derivatives	9,969	10,367	11,031
Other	50,328	29,506	24,045
Total deferred credits and other liabilities	540,019	471,161	500,832
Commitments and contingencies (see Note 11)			
Total capitalization and liabilities	$ 1,936,101	$ 1,843,560	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

Thousands	**Nine Months Ended September 30, 2007**	**2006**
Operating activities:		
Net income	$ 44,784	$ 33,303
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	50,930	47,988
Deferred income taxes and investment tax credits	4,952	(2,522)
Undistributed earnings from equity investments	(174)	(314)
Deferred gas savings - net	26,572	1,791
Non-cash expenses related to qualified defined benefit pension plans	3,301	4,122
Deferred environmental costs	(6,068)	(4,700)
Income from life insurance investments	(1,510)	(2,196)
Other	(2,262)	9,403
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	114,844	113,816
Inventories of gas, materials and supplies	(10,743)	(18,370)
Income taxes receivable	(15,111)	1,182
Prepayments and other current assets	5,696	7,421
Accounts payable	(56,221)	(70,776)
Accrued interest and taxes	(1,009)	7,882
Other current and accrued liabilities	2,701	(5,832)
Cash provided by operating activities	160,682	122,198
Investing activities:		
Investment in utility plant	(65,296)	(67,936)
Investment in non-utility property	(18,330)	(793)
Proceeds from life insurance	134	3,930
Contributions to non-utility investments	(2,688)	
Other	2,662	(164)
Cash used in investing activities	(83,518)	(64,963)
Financing activities:		
Common stock issued, net of expenses	1,590	2,350
Common stock repurchased	(34,420)	(1,608)
Long-term debt retired	(29,500)	(8,000)
Change in short-term debt	12,000	(23,400)
Cash dividend payments on common stock	(28,693)	(28,534)
Other	734	499
Cash used in financing activities	(78,289)	(58,693)
Decrease in cash and cash equivalents	(1,125)	(1,458)
Cash and cash equivalents - beginning of period	5,767	7,143

Cash and cash equivalents - end of period	$ 4,642	$ 5,685
Supplemental disclosure of cash flow information:		
Interest paid	$ 19,847	$ 20,293
Income taxes paid	$ 45,500	$ 20,020

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Financial Statements

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), consisting of our regulated gas distribution business and our regulated gas storage business, and our equity investments and other non-regulated businesses, including wholly-owned subsidiaries NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch).

The information presented in the interim consolidated financial statements is unaudited, but includes all material adjustments, including normal recurring accruals, that management considers necessary for a fair statement of the results for each period reported. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2006 Annual Report on Form 10-K (2006 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

Certain prior year balances on our consolidated balance sheets and statements of cash flows have been reclassified to conform with the current presentation. The financial statement classification was changed to reflect the current portion of regulatory assets and liabilities, which was previously included in a separate regulatory section on the balance sheet, and the current portion of fair value of non-trading derivative assets and liabilities, which was included under other assets or other liabilities. These reclassifications had no impact on our prior year s consolidated results of operations and no material impact on our financial condition or cash flows.

2. New Accounting Standards

Adopted Standards

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

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

We are subject to U.S. federal income taxes as well as several state and local income taxes. All of our U.S. federal income tax matters audited by the Internal Revenue Service through the 2004 tax year were concluded during 2006 with no material adjustments. Also, substantially all material state and local income tax matters are closed through the 2002 tax year. Based upon our assessment in connection with the adoption of FIN 48, we do not believe there are any tax positions taken that would not be fully sustained upon audit.

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

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

Recent Accounting Pronouncements

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

Fair Value Option for Financial Assets and Liabilities. In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 159, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

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

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3. Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income (loss)	$ (5,908)	$ (9,724)	$ 44,784	$ 33,303
Average common shares outstanding - basic	26,609	27,556	26,945	27,568
Additional shares for stock-based compensation plans			164	118
Average common shares outstanding - diluted	26,609	27,556	27,109	27,686
Earnings (loss) per share of common stock - basic	$ (0.22)	$ (0.35)	$ 1.66	$ 1.21
Earnings (loss) per share of common stock - diluted	$ (0.22)	$ (0.35)	$ 1.65	$ 1.20

For the three months ended September 30, 2007, 189,827 common shares were excluded from the calculation of earnings per share as there was a net loss for the period. For the nine months ending September 30, 2007, no common shares were excluded from the calculation of diluted earnings per share because the effect of all shares was dilutive. For the three and nine months ended September 30, 2006, 112,957 and 105,600 common shares were excluded, respectively, from the calculation of diluted earnings per share because the effect of these shares would have been anti-dilutive.

4. Capital Stock

At September 30, 2007, we had 60,000,000 common shares authorized and 26,584,575 common shares outstanding.

We have in place a repurchase program for our common stock, which was originally approved by the Board of Directors (Board) in May 2000. In April 2007, the Board extended the program through May 31, 2008, further increased the authorization from 2.6 million shares to 2.8 million shares and further increased the dollar limit from $85 million to $100 million. During the nine months ended September 30, 2007, 744,428 shares of our common stock were repurchased for $34.0 million, pursuant to this program. At September 30, 2007, we had 894,472 shares, or up to $26.9 million, that remain authorized under the program.

5. Stock-Based Compensation

Our stock-based compensation plans consist of the Long-Term Incentive Plan (LTIP), the Restated Stock Option Plan (Restated SOP), the Employee Stock Purchase Plan (ESPP) and the Non-Employee Directors Stock Compensation Plan (NEDSCP). These plans are designed to promote stock ownership by employees and officers and, in the case of the NEDSCP, non- employee directors. For additional information on our stock-based compensation, see Part II, Item 8., Note 4, in the 2006 Form 10-K and current updates provided below.

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In November 2005, the FASB issued FSP No. SFAS 123(R)-3 (FSP 123(R)), Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards. FSP 123(R) provides an elective alternative transition method for calculating the pool of excess tax benefits available to absorb tax deficiencies recognized subsequent to the adoption of SFAS No. 123(R). We have adopted the long-form method for calculating the pool of excess tax benefits.

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

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

Risk-free interest rate	4.7%
Expected life (in years)	6.2
Expected market price volatility factor	17.2%
Expected dividend yield	3.2%
Forfeiture rate	4.4%

As of September 30, 2007, there was $0.7 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2010.

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6. Long-Term Debt

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

Thousands	Sept. 30, 2007 (Unaudited)	Sept. 30, 2006 (Unaudited)	Dec. 31, 2006
Medium-Term Notes			
First Mortgage Bonds:			
6.31 % Series B due 2007[1]	$	$ 20,000	$ 20,000
6.80 % Series B due 2007[2]		9,500	9,500
6.50 % Series B due 2008	5,000	5,000	5,000
4.11 % Series B due 2010	10,000	10,000	10,000
7.45 % Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	10,000	10,000
7.13 % Series B due 2012	40,000	40,000	40,000
8.26 % Series B due 2014	10,000	10,000	10,000
4.70 % Series B due 2015	40,000	40,000	40,000
5.15 % Series B due 2016	25,000		25,000
7.00 % Series B due 2017	40,000	40,000	40,000
6.60 % Series B due 2018	22,000	22,000	22,000
8.31 % Series B due 2019	10,000	10,000	10,000
7.63 % Series B due 2019	20,000	20,000	20,000
9.05 % Series A due 2021	10,000	10,000	10,000
5.62 % Series B due 2023	40,000	40,000	40,000
7.72 % Series B due 2025	20,000	20,000	20,000
6.52 % Series B due 2025	10,000	10,000	10,000
7.05 % Series B due 2026	20,000	20,000	20,000
7.00 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2028	10,000	10,000	10,000
7.74 % Series B due 2030	20,000	20,000	20,000
7.85 % Series B due 2030	10,000	10,000	10,000
5.82 % Series B due 2032	30,000	30,000	30,000
5.66 % Series B due 2033	40,000	40,000	40,000
5.25 % Series B due 2035	10,000	10,000	10,000
	517,000	521,500	546,500
Less long-term debt due within one year	5,000	29,500	29,500
Total long-term debt	$ 512,000	$ 492,000	$ 517,000

(1) Redeemed at maturity in March 2007.

(2) Redeemed at maturity in May 2007.

7. Credit Agreement

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

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

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

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

8. Use of Financial Derivatives

We enter into forward contracts and other financial derivatives that qualify as derivative instruments under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133). We utilize derivative financial instruments primarily to manage commodity price risk related to natural gas supply requirements (see Part II, Item 8., Note 11, in the 2006 Form 10-K).

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

	Sept. 30, 2007		Sept. 30, 2006		Dec. 31, 2006	
Thousands	**Current**	**Non-Current**	**Current**	**Non-Current**	**Current**	**Non-Current**
Fair Value Gain (Loss):						
Natural gas commodity-based derivative instruments:						
Fixed-price financial swaps	$ (24,988)	$ (4,512)	$ (23,084)	$ (6,038)	$ (33,965)	$ (6,312)
Fixed-price financial options	(430)	(3,622)			(678)	
Indexed-price physical supply	(912)	(885)	32	(2,374)	1,115	(3,271)
Physical options			43			
Foreign currency forward purchases	403		104		(135)	
Total	$ (25,927)	$ (9,019)	$ (22,905)	$ (8,412)	$ (33,663)	$ (9,583)

In the third quarter of 2007, we realized net losses of $15.5 million from the settlement of fixed-price financial derivative contracts, which were recorded as increases to the cost of gas, compared to net losses of $12.4 million in the same period of 2006. We realized net losses of $25.6 million and $5.4 million from these settlements in the nine months ended September 30, 2007 and 2006, respectively. Realized losses in the three and nine months ended September 30, 2007 from financial derivative contracts were offset by lower gas purchase costs from the underlying floating rate physical supply contracts. Foreign currency forward purchases are also included in cost of gas at settlement as they relate to purchases of gas from Canadian suppliers.

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

9. Segment Information

Our core business is the local gas distribution segment, also referred to as the utility, which involves the distribution and sale of natural gas to customers in Oregon and Washington. Another business segment, gas storage, represents natural gas storage services provided to intrastate and interstate customers and includes asset optimization services under a contract with an independent energy marketing company. The remaining business segment, other, primarily consists of non-regulated investments in alternative energy projects in California and in a Boeing 737-300 aircraft leased to Continental Airlines, our investment in a proposed natural gas pipeline project and investments in two low-income housing buildings in Portland, Oregon. Our net investment in the aircraft was reclassified to current assets as of December 31, 2006, with the original lease term that expired in September 2007, extended to September 2008. This reclassification was made with the expectation of selling the asset within 12 months. Our net investments in the alternative energy projects in California were reclassified to current assets as of September 30, 2007 and sold in October 2007 for $2.1 million plus $0.5 million for the final distribution of our portion of the investments retained cash.

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The following table presents information about the reportable segments:

	Three Months Ended September 30,			
Thousands	**Utility**	**Gas Storage**	**Other**	**Total**
2007				
Net operating revenues [1]	$ 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)
Income (loss) from financial investments	605		(24)	581
Net income (loss)	(8,644)	2,564	172	(5,908)
2006				
Net operating revenues [1]	$ 38,085	$ 3,211	$ 45	$ 41,341
Depreciation and amortization	15,975	221		16,196
Income (loss) from operations	(8,634)	2,720	(176)	(6,090)
Income from financial investments	399		255	654
Net income (loss)	(11,419)	1,496	199	(9,724)

	Nine Months Ended September 30,			
Thousands	**Utility**	**Gas Storage**	**Other**	**Total**
2007				
Net operating revenues [1]	$ 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
Income from financial investments	1,510		174	1,684
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
2006				
Net operating revenues [1]	$ 218,476	$ 9,961	$ 115	$ 228,552
Depreciation and amortization	47,327	661		47,988
Income (loss) from operations	71,480	8,653	(599)	79,534
Income from financial investments	2,196		314	2,510
Net income	28,258	4,762	283	33,303
Total assets at Sept. 30, 2006	1,796,888	35,844	10,828	1,843,560

(1) Revenues from intersegment transactions are insignificant.

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10. Pension and Other Postretirement Benefits

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

	Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2007	2006	2007	2006
Service cost	$ 2,212	$ 1,784	$ 84	$ 142
Interest cost	4,054	3,761	329	322
Expected return on plan assets	(4,595)	(4,403)		
Amortization of loss	515	805	13	
Amortization of prior service cost	400	245	52	48
Amortization of transition obligation			103	103
Net periodic benefit cost	2,586	2,192	581	615
Amount allocated to construction	(668)	(694)	(211)	(228)
Net amount charged to expense	$ 1,918	$ 1,498	$ 370	$ 387

	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2007	2006	2007	2006
Service cost	$ 6,530	$ 5,706	$ 379	$ 417
Interest cost	12,041	11,277	969	888
Expected return on plan assets	(13,867)	(13,210)		
Amortization of loss	1,592	2,638	15	
Amortization of prior service cost	891	735	151	146
Amortization of transition obligation			309	309
Net periodic benefit cost	7,187	7,146	1,823	1,760
Amount allocated to construction	(1,716)	(2,095)	(623)	(602)
Net amount charged to expense	$ 5,471	$ 5,051	$ 1,200	$ 1,158

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

Employer Contributions

During the nine months ended September 30, 2007, we did not make cash contributions to our qualified non-contributory defined benefit plans, but cash contributions in the form of ongoing benefit payments of $1.8 million were made for our unfunded, non-qualified supplemental pension plans and other postretirement benefit plans. See Part II, Item 8., Note 7, in the 2006 Form 10-K for a discussion of future payments.

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11. Commitments and Contingencies

Environmental Matters

We own, or previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation for certain sites and the preliminary nature of several environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. Costs actually incurred over time could significantly exceed the amounts of liability accrued to date, and revised estimates of future expenditures could result in material changes from time to time in the amounts of accrued liabilities. See Part II, Item 8., Note 12, in the 2006 Form 10-K.

During the second quarter of 2007, we accrued an additional $28.8 million for estimated environmental liabilities based upon new information and analysis developed by management with the assistance of outside counsel and consultants. Of the $28.8 million, $23.4 million represents the present value of estimated future expenditures of $29.2 million which has been projected over a period of two to eight years, using an average discount rate of 5.6 percent based on estimated long term borrowing rates for comparable periods. Over the next twelve months we expect payments to total $5.1 million. In year two we expect payments to be $14.2 million, while in year five we expect payments to be $5.0 million, and the remaining $10.0 million in year eight. The status of each site currently under investigation and expected recovery of such costs, are provided below.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality s (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised upland remediation investigation report and submitted it to the ODEQ for review. In the second quarter of 2007, the estimated liability for this site increased by $16.4 million based on updated information for the development of proposed studies of in-water source control and completion of remedial actions. Based on new information we accrued less than $0.1 million in the third quarter of 2007 for additional legal fees. We have accrued a total liability of $21.4 million at September 30, 2007 for the Gasco site, which includes $16.7 million on a present value basis, as well as $4.7 million, which is estimated at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

Siltronic site. We previously owned property adjacent to the Gasco site that is now the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We are currently working with the ODEQ to develop a study of manufactured gas plant wastes on the uplands portion of this site. In the second quarter of 2007, the estimated liability for this site increased by $0.8 million related to future expenditures in connection with the study, which is at the low end of the range of potential additional liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes the area adjacent to the Gasco site and the Siltronic site. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. Subsequently, 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 segment previously studied by the EPA. In the second quarter of 2007, we received a revised estimate and based upon that review, we accrued an additional liability of $9.9 million for additional expenditures related to RI/FS development and environmental remediation and monitoring after the RI/FS work plan is completed.

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In October 2005, we completed the removal of a tar deposit in the Portland Harbor, which was approved by the EPA. The total cost of removal, including technical work, oversight, consultant fees, and legal fees and ongoing monitoring, was about $10.4 million. To date, we have paid $9.6 million on work related to the removal of the tar deposit.

As of September 30, 2007, we have accrued a total liability of $11.1 million, including $6.8 million determined on a present value basis and $4.3 million related to the remainder of the Portland Harbor site, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

Central Service Center site. In September 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (the Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In early 2007, we received notice that this site has been added to the ODEQ s list of sites where releases of hazardous substances have been confirmed and its list where additional investigation or cleanup is necessary. In the second quarter of 2007, we accrued $0.5 million for estimated liabilities related to the design of an investigational plan for this site in cooperation with the ODEQ. We cannot estimate a range of liability until studies are completed.

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

Until the current year, we had not been able to determine the timing of our environmental liabilities and therefore had accrued no current liabilities prior to June 2007. The following table summarizes the accrued liabilities relating to environmental sites at September 30, 2007 and 2006 and December 31, 2006:

	Current Liabilities			**Non-Current Liabilities**		
Thousands	**Sept. 30, 2007**	**Sept. 30, 2006**	**Dec. 31, 2006**	**Sept. 30, 2007**	**Sept. 30, 2006**	**Dec. 31, 2006**
Gasco site	$ 3,066	$	$	$ 18,292	$ 2,698	$ 6,634
Siltronic site	704				30	74
Portland Harbor site	845			10,258	2,827	3,158
Central Service Center site	534				15	15
Front Street site				1,200		
Other sites				85	65	73
Total	$ 5,149	$	$	$ 29,835	$ 5,635	$ 9,954

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Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the Oregon Public Utility Commission (OPUC) approved our request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic, Portland Harbor and Front Street sites. The authorization, which was extended through January 2008 and expanded to include the Oregon Steel Mills site (see Legal Proceedings, below) and the Central Service Center site (discussed above), allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. Beginning in 2006, the OPUC authorized us to accrue interest on deferred balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses.

On a cumulative basis, we have recognized a total of $57.5 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $22.5 million has been spent to date and $35.0 million is recorded as an outstanding liability. At September 30, 2007, we had a regulatory asset of $57.5 million, which includes $22.5 million for paid expenditures, $2.7 million in accrued interest and $32.3 million for additional environmental accruals for costs expected to be paid in the future. We will continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. We currently have an insurance receivable of $1.1 million, which is not included in the regulatory asset amount. We intend to pursue recovery of this insurance receivable and environmental regulatory deferrals from our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of some portion of our environmental costs probable based on a combination of factors, including a review of the terms of our insurance policies, the financial condition of the insurance companies providing coverage, a review of successful claims filed by other utilities with similar gas manufacturing facilities, and Oregon legislation that allows an insured party to seek recovery of all sums from one insurance company. We have initiated settlement discussions with a majority of our insurers but continue to anticipate that our overall insurance recovery effort will extend over several years.

We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we will not 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 regulatory assets relating to environmental sites at September 30, 2007 and 2006 and December 31, 2006:

	Non-Current Regulatory Assets		
Thousands	**Sept. 30, 2007**	**Sept. 30, 2006**	**Dec. 31, 2006**
Gasco site	$ 27,492	$ 5,720	$ 10,336
Siltronic site	1,227	437	477
Portland Harbor site	26,775	16,402	16,769
Central Service Center site	1,226		
Front Street site			
Other sites	807	277	291
Total	$ 57,527	$ 22,836	$ 27,873

Legal Proceedings

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

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Oregon Steel Mills site. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (Port) in a Multnomah County Circuit Court case, *Oregon Steel Mills, Inc. v. The Port of Portland*. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The Port s complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. In March 2005, motions to dismiss by ourselves and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that we were in violation of law was an affirmative defense that may be asserted at trial, but did not provide a sufficient basis for dismissal of the Port s claim. No date has been set for trial and discovery is ongoing. We received regulatory authorization from the OPUC for the deferral of environmental costs related to this site (see Regulatory and Insurance Recovery for Environmental Matters, above). We do not expect that the ultimate disposition of this matter will have a material adverse effect on our financial condition, results of operations or cash flows.

12. Comprehensive Income

Items that are excluded from net income and charged directly to common stock equity are included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in common stock equity is $2.3 million at September 30, 2007, which is related to employee benefit plan liabilities. The following table provides a reconciliation of net income to total comprehensive income for the three and nine months ended September 30, 2007 and 2006.

Thousands	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Net income (loss)	$ (5,908)	$ (9,724)	$ 44,784	$ 33,303
Amortization of employee benefit plan liability, net of tax	32		96	
Total comprehensive income (loss)	$ (5,876)	$ (9,724)	$ 44,880	$ 33,303

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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, 2007 and 2006. Unless otherwise indicated, references in this discussion to Notes are to the Notes to Consolidated Financial Statements in this report.

The consolidated financial statements include the accounts of NW Natural, which 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, including our wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch). In this report, the term utility is used to describe our regulated gas distribution business, and the term non-utility is used to describe our gas storage business segment (gas storage) and our other non-regulated investments and business activities (other), including investments in a recently announced intrastate pipeline project in Oregon (Palomar Pipeline) (see Strategic Opportunities, below, and Note 9).

Certain prior year balances on our consolidated balance sheets and statements of cash flows have been reclassified to conform with the current presentation. The financial statement classification was changed to reflect the current portion of regulatory assets and liabilities, which previously was included in a separate regulatory section on the balance sheet, and the current portion of fair value of non-trading derivative assets and liabilities, which previously was included under other assets or other liabilities. These reclassifications had no impact on our prior year s consolidated results of operations, and no material impact on our financial condition or cash flows.

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on earnings. All references in this section to earnings per share are on the basis of diluted shares (see Note 3, above, and Part II, Item 8., Note 1, Earnings Per Share, in the 2006 Form 10-K).

Executive Summary

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

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

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Our other segment represents less than 1 percent of consolidated total assets, including the recently announced investment opportunities which we intend to pursue as part of our growth strategy (see Strategic Opportunities, below).

Highlights from the third quarter of 2007 include:

- a net loss of $5.9 million, which represents a 39 percent improvement over last year s net loss of $9.7 million;
- an increase in net operating revenues of $6.6 million or 17 percent from our gas utility and a $1.7 million increase or 54 percent from our gas storage business;
- net utility customer growth of 16,254 customers, for an annual growth rate of 2.6 percent over last year, which represents a slower annual growth rate than past years but still above the national average;
- higher operations and maintenance expenses, up 6 percent for the quarter over last year;
- ranking the best among gas utilities in the West, and second highest in the nation, on overall customer satisfaction, according to the 2007 J.D. Power & Associates Gas Utility Residential Customer Satisfaction Study;
- renewal of our Conservation Tariff and Weather Normalization mechanisms by the OPUC;
- approval of a new tariff in Oregon, and the first program of its kind for a standalone gas company in the U.S., which allows customers to purchase carbon offsets for their greenhouse gas emissions;
- plans to pursue investments in a natural gas pipeline in Oregon and a proposed 20 Bcf underground gas storage facility near Fresno, California (see Strategic Opportunities, below);
- common stock repurchases totaling $10.8 million during the quarter; and
- an increase in our quarterly dividend of 2 cents a share, or 6 percent, to 37.5 cents a share payable on November 15, 2007.

Issues, Challenges and Performance Measures

There are a number of issues and challenges that affect our operations and financial performance. The most significant challenge we face in the near term continues to be managing the utility business in a period of gas price volatility. Our gas acquisition strategy is to secure sufficient supplies of natural gas to meet the needs of our utility s firm customers, but equally important is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon the market outlook and our core utility s load forecast. In 2006, we hedged the prices on a majority of our November 2006-October 2007 (2006/07) gas purchase requirements but at a slightly lower level than in prior years. During the 2006/07 contract year, spot gas prices fell and we were able to take advantage of the lower gas costs on the unhedged portion of our gas purchases, resulting in significant commodity savings that were shared by our utility customers and shareholders. In 2007, we continued to hedge the prices for a majority of our gas purchase requirements for the upcoming contract year (2007/08), with the percent currently hedged about the same as in 2006. For the 2007/08 period we expect that the prices for unhedged gas purchases will remain at risk to higher prices. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but price increases could change our earnings outlook and our competitive advantage. If gas prices increase, it could significantly affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses energy needs to alternative fuel sources (see Part I, Item 1A., Risk Factors Gas Prices and Risk Factors Competition, in the 2006 Form 10-K). To address these competitive issues, we continue to develop new gas acquisition strategies to manage gas prices and meet market demands, and we continue to work on initiatives that are intended to improve operational efficiencies throughout the company (see Part II, Item 7., Executive Summary Issues, Challenges and Performance Measures, in the 2006 Form 10-K).

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Another challenge is maintaining our customer growth rate, which is largely driven by residential new construction. While we expect to continue with a customer growth rate above the national average for local gas distribution companies due to the growing market in the Pacific Northwest, we are experiencing a slowdown in new construction and expect the slowdown to continue through 2008. For the 12 months ended September 30, 2007, our current annual growth rate was 2.6 percent, compared to 3.4 percent for the comparable period ended September 30, 2006. A prolonged slowdown in residential new construction could adversely impact our future results of operations (see Part II, Item 1A., Risk Factors Customer Growth, in the 2006 Form 10-K.

Strategic Opportunities

Business Process Redesign Update. In 2006, we initiated a project to evaluate our business processes and costs against our peers and to redesign those processes where long-term efficiencies could be gained. We targeted a number of areas where we could restructure to gain efficiencies, including more centralization and more standardized processes. As a result of these changes, to date we have reduced our employee count since the beginning of 2006 by about 10 percent and are on schedule to meet the anticipated workforce reductions of 150-200 employees by late 2009. We are also scheduled to complete and implement the first phase of a new integrated information system by January 1, 2008, which is expected to help facilitate additional initiatives. For more information regarding our redesign efforts, see Part II, Item 7., Strategic Opportunities, in the 2006 Form 10-K.

Pipeline Diversity. In September 2006, we announced that we were evaluating a possible equity investment in a natural gas pipeline project that would connect TransCanada Gas Transmission Northwest s (GTN) interstate transmission line to our local gas distribution system (Palomar Pipeline). The proposed pipeline is intended to diversify our gas delivery options, including supplies from potential liquefied natural gas facilities, and enhance reliability for our customers by providing an alternate transportation path for, and an alternative gas supply source to, gas purchases in Alberta. During the planning and permitting phase we expect to contribute our 50 percent share of the estimated $30 million in costs over the next two years. In August 2007, we entered into an agreement with GTN for the purpose of developing, designing, permitting, constructing and owning the pipeline that would serve markets in Oregon and the western United States. The project is subject to approval by the Federal Energy Regulatory Commission (FERC).

Gas Storage Development. In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California. We formed a wholly-owned subsidiary of NW Natural, Gill Ranch Storage, LLC, which will initially own 75 percent of the project and operate the facility. The new storage facility is expected to provide approximately 20 Bcf of underground gas storage capacity, plus approximately 25 miles of pipeline, when the initial phase is complete. We estimate our share of the total cost for the initial phase of development to be approximately $150 million over the next three years, which represents 75 percent of the estimated project cost. In October 2007, Gill Ranch commenced a process, known as an open season, to determine if there is sufficient interest from potential storage customers to warrant proceeding with the project. The project is subject to regulatory approval by the California Public Utilities Commission.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (GAAP), 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.

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

Within the context of our critical accounting policies and estimates, management is not currently aware of any reasonably likely events or circumstances that would result in materially different amounts being reported.

Regulatory Accounting

We are regulated by the OPUC and WUTC, which establish our utility rates and rules governing utility services provided to customers, and, to a certain extent, set forth the accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, certain accounting principles, primarily Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, require different accounting treatment for regulated companies to show the effects of such regulation. For example, we account for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC (see Results of Operations Regulatory Matters Rate Mechanisms, below). There are other expenses or revenues that the OPUC or WUTC may require us to defer for recovery or refund in future periods. SFAS No. 71 requires us to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When we are allowed to recover these expenses from or refund them to customers, we recognize the expense or revenue on the income statement at the same time we realize the adjustment to amounts included in utility rates charged to customers.

The conditions we must satisfy to adopt the accounting policies and practices of SFAS No. 71, which are applicable to regulated companies, include:

- an independent regulator sets rates;
- the regulator sets the rates to cover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

We continue to apply SFAS No. 71 in accounting for our regulated utility operations. Future regulatory changes or changes in the competitive environment could require us to discontinue the application of SFAS No. 71 for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers. Based on current regulatory and competitive conditions, we believe that it is reasonable to expect continued application of SFAS No. 71 for our regulated activities, and that all of our regulatory assets and liabilities at September 30, 2007 are recoverable or refundable through future customer rates. See Part II, Item 8., Note 1, Industry Regulation, in the 2006 Form 10-K.

During 2005, the Oregon legislature passed legislation, effective January 1, 2006, intended to ensure that utilities do not collect in rates more income taxes than they actually pay to taxing authorities. The OPUC adopted permanent rules to implement this legislation in September 2006, which were subsequently amended, with the revised rules approved in September 2007. If amounts paid and amounts collected differ by more than $100,000, the OPUC is required to direct the utility to implement a rate schedule with an automatic adjustment clause to refund or surcharge the difference to customers. In the third quarter of 2007, we determined that implementation of the rate adjustment for income taxes became probable with the issuance and approval of the revised rules in September 2007 and recognized the recovery of 2006 and 2007 estimated surcharges of $4.3 million.

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Accounting for Contingencies

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

With respect to environmental liabilities and related costs, we accrued an additional $28.8 million of contingent liabilities in the second quarter of 2007 related to properties we own, or previously owned, that require further study, investigation and possible remediation. These additional amounts accrued were developed with the assistance of outside consultants and legal counsel and were based on a review of information available from recently completed studies and negotiations involving several sites. Of the $28.8 million, $23.4 million is the present value of estimated future expenditures of $29.2 million over a period of two to eight years. Using sampling data, feasibility studies, existing technology and enacted laws and regulations, we estimated that the total future expenditures for environmental investigation, monitoring and remediation are $35.0 million as of September 30, 2007. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, then it is our policy to accrue at the lower end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated, and therefore we have recorded the liabilities at an amount that reflects the most likely estimate or the low end of the range.

In connection with environmental liability accrual during the second quarter of 2007, we recorded a corresponding regulatory asset of $28.8 million based on regulatory deferral authority from the OPUC of environmental costs associated with each of the sites affected. The authorization, which is currently extended through January 2008, allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. As of September 30, 2007, we have recognized a regulatory asset of $57.5 million which includes $22.5 million of actual expenditures to date and interest plus accruals for additional future estimated costs of $35.0 million. We will continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. If it is determined that both the insurance recovery and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. See Note 11.

Earnings and Dividends

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

Net income for the three months ended September 30, 2007 was a loss of $5.9 million, or 22 cents per share, compared to a loss of $9.7 million, or 35 cents per share, for the same period last year. We typically incur losses during the third quarter, reflecting low summertime use of natural gas, and experience stronger financial results during the colder winter months when gas use is greater.

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The primary factors contributing to improved third quarter results were:

- increased utility net operating revenues (margin) of $1.3 million, or 2.3 percent, from residential and commercial sales due to customer growth (see Results of Operations Comparison of Gas Distribution Operations, below);
- increased margin of $4.3 million from a regulatory adjustment for income taxes;
- increased margin of $1.7 million from gas storage due to an expansion of firm storage capacity and higher revenue sharing from our asset optimization arrangement; and
- a $0.4 million fair value gain from the reversal of an unrealized loss in prior periods related to derivative contracts that settled in the third quarter.

Partially offsetting the above positive factors were:

- increased operations and maintenance expense of $1.5 million, largely due to higher incentive bonus accruals tied to improved results;
- increased depreciation expense of $1.0 million related to increased utility plant in service; and
- decreased income tax benefits related to a smaller taxable loss for the period.

Nine months ended September 30, 2007 compared to September 30, 2006:

Net income was $44.8 million, or $1.65 per share, for the nine months ended September 30, 2007, compared to $33.3 million, or $1.20 per share, for the same period last year.

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

- increased utility volumes and sales to residential and commercial customers from customer growth (see Results of Operations Comparison of Gas Distribution Operations, below);
- increased margin of $4.3 million from a regulatory adjustment for income taxes;
- increased margin from regulatory sharing of gas cost savings, from $3.7 million in the first nine months of 2006 to $10.8 million in 2007;
- increased margin of $3.2 million from gas storage due to an expansion of firm storage capacity and higher revenue sharing from our asset optimization arrangement; and

- a $2.6 million fair value gain from the reversal of an unrealized loss in the fourth quarter of 2006 related to derivative contracts that settled in 2007.

Partially offsetting the above positive factors were:

- increased depreciation expenses related to increased utility plant in service;
- increased operations and maintenance expenses due to $1.1 million in damages caused by heavy rains and a $1.3 million increase in information technology costs for the implementation of a new integrated information system; and
- increased income tax expense related to higher taxable income.

Dividends paid on our common stock were 35.5 cents per share and 34.5 cents per share in the three months ended September 30, 2007 and 2006, respectively, and $1.065 per share and $1.035 per share in the nine months ended September 30, 2007 and 2006, respectively. In October 2007, the Board declared a quarterly dividend on our common stock of 37.5 cents per share payable on November 15, 2007, to shareholders of record on October 31, 2007. The current indicated annual dividend rate is $1.50 per share.

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Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. Typically, about 90 percent of our utility gas deliveries and operating revenues are derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the pace of continued growth in the residential and commercial markets and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant. See Part II, Item 7., Results of Operations Regulatory Matters, in the 2006 Form 10-K.

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

		Current	
Thousands	**Sept. 30, 2007**	**Sept. 30, 2006**	**Dec. 31, 2006**
Regulatory assets:			
Gas costs receivable	$	$ 4,729	$
Unrealized loss on non-trading derivatives[1]	27,104	32,098	30,798
Other	875	692	711
Total regulatory assets	$ 27,979	$ 37,519	$ 31,509
Regulatory liabilities:			
Gas costs payable	$ 37,581	$	$ 737
Unrealized gain on non-trading derivatives[1]	1,423	9,193	
Other	12,477	9,812	11,182
Total regulatory liabilities	$ 51,481	$ 19,005	$ 11,919

		Non-Current	
Thousands	**Sept. 30, 2007**	**Sept. 30, 2006**	**Dec. 31, 2006**
Regulatory assets:			
Gas costs receivable	$	$ 454	$
Unrealized loss on non-trading derivatives[1]	9,969	10,367	9,584
Income tax asset	68,086	66,757	67,141
Pension and other postretirement benefit obligations[2]	51,770		54,425
Environmental costs - paid[3]	25,181	17,138	19,113
Environmental costs - accrued but not yet paid[3]	32,346	5,698	8,760
Other	9,981	5,872	5,748
Total regulatory assets	$ 197,333	$ 106,286	$ 164,771
Regulatory liabilities:			
Gas costs payable	$ 2,769	$	$ 13,041
Unrealized gain on non-trading derivatives[1]	950	1,955	
Accrued asset removal costs	200,590	182,725	187,422
Other	2,333	2,487	2,519
Total regulatory liabilities	$ 206,642	$ 187,167	$ 202,982

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

[2] Pension and other postretirement benefit obligations related to projected benefits are approved for regulatory deferral, principally based on SFAS No. 87 and SFAS No. 106 expenses included in customer rates in general rate cases (see Part II, Item 8., Note 7, in the 2006 Form 10-K).

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

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General Rate Cases

Oregon Rate Case Moratorium. In September 2007, in conjunction with the renewal of two of our rate mechanisms (see Conservation Tariff and Weather Normalization, below), the OPUC approved a stipulation that restricts us from filing a general rate case with the OPUC prior to September 1, 2011, subject to certain exceptions. We retain the right to file a general rate case request if an extraordinary event occurs or for certain exceptions that would require significant investments on behalf of our customers. These exceptions might include additional investments in our pipeline integrity management program, or expanded implementation of automated meter reading if an existing joint meter-reading program with a local electric utility ends. This agreement does not impact our ability to file annual rate adjustments to reflect changes in gas purchase costs under our PGA mechanism and to collect, or refund, prior year s gas cost deferrals.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contractual arrangements to hedge the purchase price with financial derivatives (see Comparison of Gas Distribution Operations Cost of Gas Sold, below), interstate pipeline demand charges, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year. Under the current PGA mechanisms, we collect an amount for purchased gas costs based on estimates included in rates. If the actual purchased gas costs differ from the estimated amounts included in rates, then we are required to defer that difference and pass it on to customers as an adjustment to future rates. As part of an incentive mechanism in Oregon, only 67 percent of the difference is deferred such that the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of all prudently incurred gas costs which are passed through in customer rates.

In October 2007, the OPUC and the WUTC approved rate changes effective on November 1, 2007 under our PGA mechanism. The effect of the rate changes is to reduce the average monthly bills of Oregon residential customers by 8.0 percent and those of Washington residential customers by 9.8 percent.

The OPUC is currently conducting a formal review of the PGA process used by natural gas utilities in Oregon covering gas portfolio requirements, incentive sharing levels and filing requirements, among other items. The review is expected to be completed in 2008. Implementation of any changes to the PGA mechanism is likely to become effective with the 2008 PGA filing (see Part I, Item 1A., Risk Factors Regulatory Risk, in the 2006 Form 10-K).

Conservation Tariff. In September 2007, the OPUC approved the extension of our conservation tariff through October 31, 2012. The tariff is a decoupling mechanism that is intended to break the link between earnings and the quantity of energy consumed by customers, removing any incentive for us to discourage customers conservation efforts (see Part II, Item 7., Results of Operations Rate Mechanisms, in the 2006 Form 10-K).

Weather Normalization. In September 2007, the OPUC extended our weather normalization mechanism through October 31, 2012. This mechanism is designed to help stabilize utility margins by adjusting residential and commercial customer billings based on temperature variances from average weather, decreasing rates when the weather is colder than average and increasing them when it is warmer than average. The mechanism is applied to our Oregon residential and commercial customers bills between December 1 and May 15 of each heating season (see Part II, Item 7., Results of Operations Rate Mechanisms, in the 2006 Form 10-K).

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Excess Earnings Test. The OPUC has a formalized process to test for excess utility earnings annually. We are authorized to retain all of our earnings up to a threshold level equal to our authorized return on equity (ROE) of 10.2 percent plus 300 basis points. One-third of any earnings above that level will be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year depending on movements in long-term interest rates. In 2006, the ROE threshold after adjustment was 13.44 percent. In July 2007, the OPUC issued an order that no amounts will be required to be refunded to customers as a result of the 2006 earnings test. In Washington, we are not subject to an annual excess earnings test.

Integrated Resource Planning. The OPUC and WUTC have implemented integrated resource planning (IRP) processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. We filed a draft IRP with the WUTC in the first quarter of 2007, and we expect to file a draft IRP with the OPUC by the end of this year.

Interstate Pipeline Rate Cases

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

Regulatory Adjustment for Income Taxes

During 2005, the Oregon legislature passed legislation, effective January 1, 2006, intended to ensure that utilities do not collect in rates more income taxes than they actually pay to taxing authorities. The OPUC adopted permanent rules to implement this legislation in September 2006, which were subsequently amended, with the revised rules approved in September 2007. The OPUC rules require us to identify the amount of income taxes paid, as well as the amount of taxes authorized to be collected in rates during the tax year. If amounts paid and amounts collected differ by more than $100,000, the OPUC is required to direct the utility to implement a rate schedule with an automatic adjustment clause to refund or surcharge for the difference. The first tax year for implementation of the automatic adjustment clause for us is the 2006 tax year. For more information regarding this requirement, see Part II, Item 7., Results of Operations Regulatory Matters Utility Regulation Legislation, in the 2006 Form 10-K; Application of Critical Accounting Policies and Estimates Regulatory Accounting, above; and Comparison of Gas Distribution Operations Regulatory Adjustment for Income Taxes, below).

In the third quarter of 2007, we determined that implementation of the rate adjustment for income taxes became probable following the issuance and approval of revised rules by the OPUC in September 2007 and recognized the recovery of 2006 and 2007 estimated surcharges of $4.3 million. Our request for a Private Letter Ruling from the Internal Revenue Service (IRS) on the issue of whether this law complies with the provisions of federal tax law, including the normalization requirements of the Internal Revenue Code, is pending. An adverse ruling by the IRS could result in a reversal of amounts accrued. Given our current corporate structure and level of non-utility investments and activities, we expect that ongoing compliance with this law, as currently interpreted, will not have a material adverse effect on our financial condition, results of operations or cash flows.

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Comparison of Gas Distribution Operations

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

Thousands, except degree day and customer data	Three months ended September 30, 2007	Three months ended September 30, 2006	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	28,715	27,832	883
Commercial sales	27,067	26,693	374
Industrial - firm sales	11,206	12,306	(1,100)
Industrial - firm transportation	39,116	39,391	(275)
Industrial - interruptible sales	19,053	21,964	(2,911)
Industrial - interruptible transportation	59,808	57,872	1,936
Total utility volumes sold and delivered	184,965	186,058	(1,093)
Utility operating revenues - dollars:			
Residential sales	$ 48,345	$ 45,207	$ 3,138
Commercial sales	35,045	33,412	1,633
Industrial - firm sales	12,190	13,157	(967)
Industrial - firm transportation	1,439	1,328	111
Industrial - interruptible sales	16,427	17,691	(1,264)
Industrial - interruptible transportation	1,990	2,020	(30)
Regulatory adjustment for income taxes (1)	4,313		4,313
Other revenues	(500)	(1,168)	668
Total utility operating revenues	119,249	111,647	7,602
Cost of gas sold	71,554	70,623	(931)
Revenue taxes	3,012	2,939	(73)
Utility net operating revenues (margin)	$ 44,683	$ 38,085	$ 6,598
Utility margin:			
Residential sales	$ 22,413	$ 21,618	$ 795
Commercial sales	10,750	10,293	457
Industrial - sales and transportation	7,203	7,682	(479)
Regulatory adjustment for taxes (1)	4,313		4,313
Miscellaneous revenues	1,006	695	311
Other margin adjustments	611	(738)	1,349
Margin before regulatory adjustments	46,296	39,550	6,746
Weather normalization mechanism			
Decoupling mechanism	(1,613)	(1,465)	(148)
Utility margin	$ 44,683	$ 38,085	$ 6,598
Customers - end of period:			
Residential customers	578,362	562,752	15,610
Commercial customers	60,170	59,519	651
Industrial customers	930	937	(7)
Total number of customers - end of period	639,462	623,208	16,254

Actual degree days	123	79
Percent colder (warmer) than average [2]	21%	(23%)

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Thousands, except degree day data	Nine months ended September 30, 2007	2006	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	251,896	242,231	9,665
Commercial sales	166,441	162,028	4,413
Industrial - firm sales	38,815	51,862	(13,047)
Industrial - firm transportation	118,504	104,482	14,022
Industrial - interruptible sales	65,477	89,784	(24,307)
Industrial - interruptible transportation	190,723	173,185	17,538
Total utility volumes sold and delivered	831,856	823,572	8,284
Utility operating revenues - dollars:			
Residential sales	$ 361,589	$ 340,650	$ 20,939
Commercial sales	203,895	192,934	10,961
Industrial - firm sales	40,985	51,156	(10,171)
Industrial - firm transportation	4,407	3,445	962
Industrial - interruptible sales	56,153	73,427	(17,274)
Industrial - interruptible transportation	6,110	5,747	363
Regulatory adjustment for income taxes (1)	4,313		4,313
Other revenues	10,666	(1,206)	11,872
Total utility operating revenues	688,118	666,153	21,965
Cost of gas sold	431,748	431,014	(734)
Revenue taxes	17,013	16,663	(350)
Utility net operating revenues (margin)	$ 239,357	$ 218,476	$ 20,881
Utility margin:			
Residential sales	$ 139,653	$ 133,522	$ 6,131
Commercial sales	58,092	55,769	2,323
Industrial - sales and transportation	23,063	23,872	(809)
Regulatory adjustment for taxes (1)	4,313		4,313
Miscellaneous revenues	3,986	3,343	643
Other margin adjustments	11,473	2,684	8,789
Margin before regulatory adjustments	240,580	219,190	21,390
Weather normalization mechanism	(1,454)	2,686	(4,140)
Decoupling mechanism	231	(3,400)	3,631
Utility margin	$ 239,357	$ 218,476	$ 20,881
Actual degree days	2,673	2,465	
Percent colder (warmer) than average (2)	1%	(7%)	

(1) Regulatory adjustment for income taxes is the result of the implementation of the utility regulation as described above under Regulatory Matters Regulatory Adjustment for Income Taxes, and below under Regulatory Adjustment for Income Taxes.

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

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

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Our utility results are affected by, among other things, customer growth and changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In order to offset the potential volatility in utility earnings caused by weather and declining consumption due to conservation, we obtained OPUC approval of a conservation tariff that adjusts margin up or down based on changes in residential and commercial customer consumption and a weather normalization mechanism that adjusts customer bills, and our margin, based on above- or below-average temperatures during the winter heating season (see Regulatory Matters Rate Mechanisms, above, and Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2006 Form 10-K).

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

Utility operations resulted in a net loss of $8.6 million, or 32 cents per share, in the third quarter of 2007 compared to a net loss of $11.4 million, or 41 cents per share, in 2006. Net income from utility operations is typically low during the third quarter due to the reduced use of natural gas in the summer. Total utility volumes sold and delivered in the third quarter of this year was about the same as last year, while total utility margin increased by 17 percent, primarily due to the recognition of the amounts we expect to collect under an automatic adjustment clause calculating the difference between actual taxes paid and the amounts we collect from customers in rates of $4.3 million.

Nine months ended September 30, 2007 compared to September 30, 2006:

In the first nine months of 2007, utility operations contributed $37.4 million, or $1.38 per share, compared to $28.3 million, or $1.02 per share in 2006. Total utility volumes sold and delivered in the first nine months of this year increased by 1 percent over last year, while total utility margin increased by 10 percent, primarily due to the recognition of $4.3 million which we expect to collect under an automatic adjustment clause representing the difference between actual taxes paid and the amounts we collected from customers in rates.

Volume increases in both of the 2007 periods were due mainly to residential and commercial customer growth, which slowed but continued with a net increase of 16,254 customers since September 30, 2006, or an annual growth rate of 2.6 percent. Our growth rate remains above the national average for local gas distribution companies despite recent economic conditions that have moderately slowed the level of new construction in our service territory. In the three years ended December 31, 2006, more than 58,400 customers were added, representing a trailing average annual growth rate of 3.4 percent. The margin increase in the first nine months of the year was primarily driven by regulatory sharing of gas cost savings of $7.1 million and by a regulatory adjustment related to income taxes of $4.3 million (see Regulatory Adjustment for Income Taxes, and Cost of Gas Sold, below).

Residential and Commercial Sales

Residential and commercial sales markets are impacted by seasonal weather patterns, energy prices, competition from alternative energy sources and economic conditions in our service areas. Typically, 80 percent or more of our annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced due to the weather normalization mechanism in Oregon where about 90 percent of our customers are served. Approximately 10 percent of our eligible Oregon customers have opted out of the mechanism. In Oregon, we also have a conservation decoupling mechanism that is intended to break the link between our earnings and the quantity of gas consumed by our customers, so that we do not have an incentive to discourage customers from conserving energy. In Washington, where the remaining 10 percent of our customers are served, we do not have a weather normalization or a conservation decoupling mechanism. As a result, these mechanisms do not fully insulate the utility from earnings volatility due to weather and conservation. See the above tables under Comparison of Gas Distribution Operations for the adjustments to utility margin revenues from the weather normalization and decoupling mechanisms for the three and nine months ended September 30, 2007 and 2006.

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

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

- sales volumes were 2 percent higher as a result of customer growth; and operating revenues were 6 percent higher due to higher sales volumes and higher billing rates, which reflect the higher gas costs in the PGA effective November 1, 2006 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K).

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Nine months ended September 30, 2007 compared to September 30, 2006:

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

- sales volumes were 3 percent higher as a result of customer growth and weather that was 8 percent colder than last year; and
- operating revenues were 6 percent higher due to higher sales volumes and higher billing rates, which reflect the higher gas costs in the PGA effective November 1, 2006 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K).

Total utility operating revenues include accruals for unbilled revenues (gas delivered but not yet billed to customers) based on estimates of gas deliveries from that month s meter reading dates to month end. Amounts reported as unbilled revenues reflect the increase or decrease in the balance of accrued unbilled revenues compared to the prior period end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenues at the end of each month. At September 30, 2007, accrued unbilled revenue was $20.9 million, compared to $19.3 million at September 30, 2006, with the increase primarily reflecting colder weather toward the end of the third quarter of 2007 as compared to 2006.

Industrial Sales and Transportation

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

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

Total volumes delivered to industrial sales and transportation customers were down 2.4 million therms, or 2 percent, in the third quarter of 2007 as compared to the same period in 2006. Utility margin related to these customers was down $0.5 million, or 6 percent, over last year, primarily due to some temporary shut-downs of a few large customers.

Nine months ended September 30, 2007 compared to September 30, 2006:

Total volumes delivered to industrial sales and transportation customers were down 5.8 million therms, or 1 percent, in the first nine months of 2007 as compared to the same period in 2006. Utility margin related to these customers was down $0.8 million, or 3 percent, over last year. The decrease is primarily due to some temporary shut-downs of a few large customers and some switching to lower margin rate schedules.

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Regulatory Adjustment for Income Taxes

Based upon the revised rules issued by the OPUC in September 2007, we filed our 2007 Tax Report for the 2006 tax year on October 15, 2007. For that year, we estimate the utility is entitled to recover $1.7 million through a surcharge to Oregon customers based on taxes paid that were greater than taxes collected, which was primarily driven by gains from gas cost savings from the PGA incentive sharing mechanism in 2006. The increase in Oregon revenues for this surcharge is expected to go into effect June 1, 2008 and would be recovered in customer rates over the following 12-month period. For the 2007 tax year, we estimate the utility will again be entitled to a surcharge for taxes paid in excess of taxes collected in rates, largely driven by gains from gas cost savings from the PGA incentive sharing mechanism in 2007. For the nine months ended September 30, 2007, we recorded an estimated surcharge of $2.6 million. The combined 2006 and year-to-date 2007 surcharge estimates totaling $4.3 million were recorded in the third quarter of 2007 and are included in Gross operating revenues. Deferred income tax expense of $1.7 million was also recorded in the third quarter of 2007, resulting in a net contribution to earnings of $2.6 million, or 10 cents a share (see Regulatory Matters Regulatory Adjustment for Income Taxes, above).

Other Revenues

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

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

Other revenues decreased net operating revenues by $0.5 million in the third quarter of 2007, compared to a decrease of $1.2 million in the third quarter of 2006, with the $0.7 million improvement being primarily due to a $0.7 million increase in the contribution from decoupling regulatory deferrals and amortization.

Nine months ended September 30, 2007 compared to September 30, 2006:

Other revenues were $10.7 million in the first nine months of 2007, compared to a $1.2 million net expense in the first nine months of 2006, with the increase being primarily due to a $9.8 million increase in the contribution from decoupling regulatory deferrals and amortization and a $1.7 million increase in gas storage credits.

Cost of Gas Sold

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

The total cost of gas sold in the third quarter of 2007 was $71.6 million, an increase of $0.9 million, or 1 percent, compared to the third quarter of 2006. The total cost of gas sold in the first nine months of 2007 was $431.7 million, an increase of $0.7 million, compared to the prior year. During the third quarter and nine months ended September 30, 2007, the cost per therm of gas sold was 5 percent higher than in the comparable 2006 periods. The cost of gas sold increased as volumes to residential and commercial customers increased, but was more than offset by the decrease in volumes sold to industrial customers and lower gas prices. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity price hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

Under the PGA tariff in Oregon, our net income is affected by a sharing mechanism based on increases or decreases in purchased gas costs as compared to estimated gas costs included in customer rates (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K). In the third quarter of 2007, our share of gas cost savings contributed $0.2 million to margin, the same contribution to margin as in the third quarter of 2006. In the first nine months of 2007, our share of gas cost savings contributed $10.8 million to margin, compared to a $3.7 million contribution to margin in the first nine months of 2006. The net benefit to utility customers from aggregate gas cost savings amounted to $0.7 million and $24.8 million for the three- and nine -month periods ended September 30, 2007, respectively. Because the volatility of gas prices cannot be predicted, the current contribution from this sharing mechanism may not be indicative of future results.

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We use a natural gas commodity-price hedge program under the terms of our Financial Derivatives Policy to help manage our exposure to floating price gas purchase contracts (see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2006 Form 10-K, and Note 8, above). We realized net losses of $15.5 million from our financial hedges in the third quarter of 2007, compared to net losses of $12.4 million in the same period of 2006. In the first nine months of 2007, we realized net losses of $25.6 million from our financial hedges, compared to net losses of $5.4 million in the first nine months of 2006. These losses were included in the hedged gas prices approved in rates, and therefore did not have a material impact on our results of operations.

Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, which are factored into our PGA deferrals and annual rate changes, but to the extent that any utility gas hedge is entered into after the annual PGA filing, then the gains and losses are subject to our PGA incentive sharing mechanism, with 67 percent of the net gain or loss deferred to a regulatory account and 33 percent recorded to current income. We recorded $0.4 million and $2.6 million as credits to the cost of gas in the third quarter and first nine months of 2007, respectively, related to a fair value adjustment on financial derivative contracts that were entered into during the fourth quarter of 2006 after the 2006 PGA filing (see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2006 Form 10-K).

Business Segments Other than Gas Distribution Operations

Gas Storage

Net income from our gas storage business segment in the three and nine months ended September 30, 2007 was $2.5 million and $7.0 million, respectively, after regulatory sharing and income taxes, or 9 cents and 26 cents per share, respectively. This compares to net income of $1.5 million, or 5 cents per share, and $4.8 million, or 17 cents per share, in the three and nine months ended September 30, 2006, respectively. This current year increase was primarily due to increased firm storage capacity and increased revenues from our asset optimization arrangement with the independent energy marketing company (see Part II, Item 7., Results of Operations Business Segments Other Than Local Gas Distribution Gas Storage, in the 2006 Form 10-K).

Third-party optimization is provided pursuant to a contract with an independent energy marketing company, which assists in the optimization of the value of our storage and transportation capacity assets primarily through the use of commodity transactions. In Oregon, we retain 80 percent of the pre-tax income from interstate storage services and optimization activities when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such optimization when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from interstate storage services and third-party optimization.

Other

The other business segment primarily consists of a wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including an investment in a leveraged aircraft lease, our equity investment in a proposed natural gas pipeline project with GTN, and our wholly-owned subsidiary, Gill Ranch (see Note 9, above, and Part II, Item 8., Note 2, Consolidated Subsidiary Operations, in the 2006 Form 10-K). Operating results from this segment for the three and nine months ended September 30, 2007 consisted of net income of $0.2 million and $0.4 million, respectively, compared to net income of $0.2 million and $0.3 million in the three and nine months ended September 30, 2006, respectively.

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Our net investment balance in Financial Corporation at September 30, 2007 and 2006 was $3.0 million and $2.7 million, respectively. The increase primarily reflects higher cash investments due to cash distributions from our investments in alternative energy projects. These investments were sold in October 2007 for $2.1 million and our portion of the investments retained cash, resulting in an after-tax gain of $0.9 million that will be recognized in the fourth quarter (see Part II, Item 5., Other Information, below). Our net investment balance in the leveraged aircraft lease at September 30, 2007 and 2006 was $4.9 million and $7.2 million, respectively, with the decrease primarily due to the receipt in March 2007 of the final payment due under the terms of the original 20 year lease agreement. Our equity investment balance in the proposed natural gas pipeline project with GTN was $2.9 million at September 30, 2007 and a negligible amount at September 30, 2006 (see Strategic Opportunities, above).

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the third quarter of 2007 were $27.1 million, representing a $1.5 million, or 6 percent, increase over the third quarter of 2006, which in part, reflects management s approval of certain increases in operations and maintenance expense for strategic initiatives during the third and fourth quarters of 2007. The major factors contributing to the operations and maintenance increases during the third quarter were:

- a $0.7 million increase in injury and damage claims;
- a $0.3 million increase in training expense related to implementation of the first phase of a new integrated information system; and
- a $0.4 million increase in certain employee benefit costs.

Operations and maintenance expenses in the first nine months of 2007 were $84.4 million, representing a $2.6 million, or 3 percent, increase over the first nine months of 2006. The following summarizes the major factors that contributed to this increase:

- a $1.1 million increase in damages, partially due to damages caused by heavy rains;
- a $1.2 million increase in certain employee benefit costs;
- a $0.6 million increase in bonus expense;
- a $0.2 million increase in severance expense;
- a $1.3 million increase in information technology costs due to telecommunication, maintenance and training related to implementation of the first phase of a new integrated information system;
- offset, in part, by a $1.3 million decrease in wages, salaries and contract labor; and
- a $0.3 million decrease in bad debt expense due to improved collection results, which reflects a write-off rate that is less than 1 percent of gas revenues.

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, increased $0.8 million, or 14 percent, in the three months ended September 30, 2007 over the same period in 2006. The major factors contributing to this increase were:

- a $0.6 million increase in other taxes due to an increase in the annual fee paid to the Oregon Department of Energy; and

- a $0.1 million increase in payroll taxes primarily due to increased payroll expense.

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General taxes increased $ 0.3 million, or 2 percent, in the first nine months of 2007 compared to 2006. The major factors contributing to this increase were:

- a $0.3 million increase in regulatory fees based on higher revenue; and
- a $0.2 million increase in other taxes due to an increase in the annual fee to the Oregon Department of Energy;
- offset, in part by a $0.2 million decrease in property taxes.

Depreciation and Amortization

Depreciation and amortization expense increased by $1.0 million, or 6 percent, and by $2.9 million, or 6 percent, in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006. The increased expense reflects ongoing capital expenditures for utility and non-utility plant that were made primarily to meet continuing customer growth, to upgrade utility operating facilities and to expand non-utility storage capacity.

Other Income and Expense Net

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

Thousands	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Other income and expense - net:				
Gains from company-owned life insurance	$ 605	$ 399	$ 1,510	$ 2,196
Interest income	57	31	421	306
Other non-operating expense	(414)	(262)	(1,603)	(1,080)
Net interest income (expense) on deferred regulatory accounts	512	(109)	291	(494)
Gain (loss) from equity investments	(24)	255	174	314
Total other income and expense - net	$ 736	$ 314	$ 793	$ 1,242

In the quarter ended September 30, 2007, other income and expense net increased $0.4 million compared to the same period in 2006 primarily due to a $0.6 million increase in interest income on deferred regulatory accounts, offset by a $0.2 million increase in other non-operating expenses related to business development.

The $0.4 million decrease in other income and expense net in the nine months ended September 30, 2007 compared to the same period in 2006 was primarily due to a decrease of $0.7 million in gains from company-owned life insurance and a $0.5 million increase in other non-operating expense related to business development, which were offset in part by a $0.8 million change in net interest on deferred regulatory accounts.

Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized decreased $0.4 million, or 4 percent, and $1.1 million, or 4 percent, in the three and nine months ended September 30, 2007, respectively, compared to the same periods in 2006, primarily due to lower average balances of total debt outstanding resulting from increased cash flows tied to strong operating results and gas cost savings.

Income Taxes

Income tax expense totaled $26.2 million in the nine months ended September 30, 2007 compared to $18.7 million in the nine months ended September 30, 2006. The effective tax rate was 36.9 percent in 2007 compared to 35.9 percent in 2006. The higher income tax expense in 2007 is due primarily to pre-tax book income of $71.0 million compared to $52.0 million for the same period in 2006, while the increase in the effective tax rate was largely due to a $0.7 million decrease in non-taxable gains on life insurance.

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Financial Condition

Capital Structure

Our goal is to maintain a target capital structure comprised of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources also are used to meet long-term debt redemption requirements and short-term commercial paper maturities (see Liquidity and Capital Resources, below). Achieving the target capital structure and maintaining sufficient liquidity are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at September 30, 2007 and 2006 and at December 31, 2006, including short-term debt, was as follows:

	Sept. 30, 2007	Sept. 30, 2006	Dec. 31, 2006
Common stock equity	48.2%	48.7%	48.1%
Long-term debt	42.2%	40.4%	41.5%
Short-term debt, including current maturities of long-term debt	9.6%	10.9%	10.4%
Total	100.0%	100.0%	100.0%

In April 2007, the Board authorized an increase in the common stock share repurchase program, now aggregating up to 2.8 million shares, or up to $100 million in value, from the previously authorized levels of up to 2.6 million shares or up to $85 million in value. Purchases under this program are made in the open market or through privately negotiated transactions. See 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, 2007, we had $4.6 million of cash and cash equivalents compared to $5.7 million at September 30, 2006 and $5.8 million at December 31, 2006. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by a committed line of credit totaling $250 million available through May 31, 2012 (see Credit Agreement, below). Proceeds from the issuance of long-term debt are used to finance capital expenditures and refinance maturing short-term or long-term debt.

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

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

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Off-Balance Sheet Arrangements

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

Contractual Obligations

Since December 31, 2006, our estimated future contractual obligations have increased by about $12 million in 2008 and $1 million in 2009 primarily due to contracts for construction work and for the implementation of a new integrated information system, which were entered into in the ordinary course of business. Our contractual obligations at December 31, 2006 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2006 Form 10-K.

Commercial Paper

Our primary source of short-term 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 purchases and accounts receivable, short-term debt is used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by unsecured revolving loans (see Credit Agreement, below, and Part II, Item 8., Note 6, in the 2006 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 other issuers of commercial paper. We had $112.1 million in commercial paper notes outstanding at September 30, 2007, compared to $103.3 million outstanding at September 30, 2006 and $100.1 million outstanding at December 31, 2006. This year s outstanding balances were higher than last year primarily due to the redemption of $29.5 million of medium term notes during the first nine months of 2007 without any new long-term financing, see Redemptions of Long-Term Debt, below.

Credit Agreement

In May 2007, we entered into a credit agreement for unsecured revolving loans totaling $250 million with seven lenders, replacing the prior $200 million bilateral credit agreements with separate lenders which were terminated. The new credit agreement is available and committed for a term of five years expiring on May 31, 2012, which may be extended for additional one-year periods thereafter subject to lender approval. The credit agreement allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. The credit agreement continues to be used primarily as back-up credit support for the notes payable issued under our commercial paper program. Commercial paper borrowing provides the liquidity to meet our working capital and interim financing requirements. Under the terms of the credit agreement, we pay upfront fees, annual commitment fees and administrative agent fees, but we are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under the credit agreement are based on our long-term unsecured debt ratings and on then-current market interest rates. All principal and unpaid interest under the credit agreement is due and payable on May 31, 2012, subject to extensions if any. There were no outstanding balances on this credit agreement at September 30, 2007 or on prior credit agreements at September 30 or December 31, 2006.

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

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The credit agreement requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and to accelerate the maturity of any amounts outstanding. We were in compliance with this covenant at September 30, 2007. Our previous credit agreements required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at September 30 and December 31, 2006.

Credit Ratings

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

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

Both rating agencies have assigned NW Natural an investment grade credit rating. These credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. In July 2007, Moody s revised our ratings outlook from stable to positive. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

During 2007, we redeemed $29.5 million of secured Medium Term Notes at maturity, consisting of $9.5 million of secured 6.80% Series B Medium Term Notes in May and $20.0 million of secured 6.31% Series B Medium Term Notes in March. In June 2006, we redeemed $8.0 million of secured 6.05% Series B Medium Term Notes at maturity.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, gas prices, deferred income taxes, changes in working capital requirements, regulatory deferrals and other cash and non-cash adjustments to operating results. The overall change in cash flow from operating activities for the nine months ended September 30, 2007 compared to the same period in 2006 was an increase of $38.5 million. The major factors contributing to the cash flow changes in the first nine months of 2007 compared to the first nine months of 2006 are as follows:

- an increase in net income added $11.5 million to cash flow;
- deferred gas costs, primarily related to gas cost savings for customers realized in the first quarter of 2007, increased cash by $24.8 million with the cash flow expected to reverse when these savings are refunded to customers in utility rates under our PGA tariff to be effective starting in November 2007;
- an increase of $7.6 million resulting from a smaller increase in gas inventory balances in 2007 compared to 2006 reflecting lower gas prices;
- a decrease of $16.3 million in 2007 compared to 2006 due to the accrual of income taxes receivable in 2007; and

a smaller reduction in accounts payable in 2007 compared to 2006 accounted for a $14.6 million increase in cash flow primarily due to lower gas prices.

Investing Activities

Cash requirements for investing activities in the first nine months of 2007 totaled $83.5 million, up from $65.0 million in the same period of 2006. Cash requirements for utility plant totaled $65.3 million in the first nine months of 2007, down 4 percent from the $67.9 million expended in the same period of 2006.

Investments in non-utility property during the first nine months of 2007 totaled $18.3 million, up from $0.8 million during the first nine months of 2006, due primarily to amounts for the capital improvements related to expansion of our gas storage facilities and an equity investment of $2.7 million in a proposed pipeline project, offset by the receipt of $2.7 million in March 2007 under the airplane leveraged lease agreement.

Our utility and non-utility capital expenditures are expected to total about $125 million in 2007, which includes capital expenditures for an integrated information system and for gas storage development. We also expect our contributions to the Palomar Pipeline to total about $12 million over the next two years.

Financing Activities

Cash used in financing activities in the first nine months of 2007 totaled $78.3 million, up from $58.7 million in the same period of 2006. The primary factors contributing to the $19.6 million increase were differences in debt financings and increased common stock repurchase activity. Debt financing consisted of a net decrease of $17.5 million in short-term and long-term debt outstanding in the first nine months of 2007, compared to a net decrease of $31.4 million in 2006. Under our common stock repurchase program, we purchased 744,428 shares at a total cost of $34.0 million in the first nine months of 2007, compared to 47,100 shares at a total cost of $1.6 million in the first nine months of 2006.

Pension Funding Status

Our policy is to fund the qualified defined benefit pension plans as needed, based on tax regulations and funding requirements under federal law, including funding the amounts required by the Employee Retirement Income Security Act of 1974. In addition, it is our intent to contribute sufficient amounts as needed on an actuarial basis to maintain funding targets and to provide for the timely payment of future benefits under these plans. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Part II, Item 7., Pension Cost and Funding Status of Qualified Retirement Plans, and Part II, Item 8., Note 7, Pension and Other Postretirement Benefits, in the 2006 Form 10-K.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of loss is reasonably estimable in accordance with SFAS No. 5, Accounting for Contingencies. For further discussion, see Part II, Item 7., Contingent Liabilities, in the 2006 Form 10-K.

We develop estimates of environmental liabilities and related costs based on currently available information, existing technology and environmental regulations. These costs include investigation, monitoring and remediation. We received regulatory approval to defer and seek recovery of costs related to certain sites and believe the recovery of these costs is probable through the regulatory process. In accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, we have recorded a regulatory asset for the amount expected to be recovered. We intend to pursue recovery of these environmental costs from our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. During the second quarter of 2007, we accrued additional amounts totaling $28.8 million based upon new information and analysis developed by management with the assistance of outside counsel and consultants. At September 30, 2007, we had a regulatory asset of $57.5 million, which includes $22.5 million for paid expenditures, $2.7 million in accrued interest and $32.3 million for additional environmental accruals for costs expected to be paid in the future. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made (see Note 11, above).

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Ratios of Earnings to Fixed Charges

For the nine months and 12 months ended September 30, 2007 and the 12 months ended December 31, 2006, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.35, 3.80 and 3.40, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. Because a significant part of our business is of a seasonal nature, the ratio for the interim period is not necessarily indicative of the results for a full year.

Forward-Looking Statements

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

- prevailing state and federal governmental policies and regulatory actions, including those of the OPUC and the WUTC, with respect to allowed rates of return, industry and rate structure, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in tax laws and policies and changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity;
- implementation by the OPUC of final rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;
- weather conditions, pandemic events and other natural phenomena, including earthquakes or other geohazard events;
- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;
- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- the creditworthiness of customers, suppliers and financial derivative counterparties;

- our dependence on a single pipeline transportation provider for natural gas supply;
- property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- financial and operational risks relating to business development and investments activities, including the proposed natural gas pipeline project with GTN and the proposed Gill Ranch storage facility;
- unanticipated changes that may affect our liquidity or access to capital markets;
- the execution of our business process redesign;
- our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;
- unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;
- economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;
- unanticipated changes in operating expenses and capital expenditures;
- changes in estimates of potential liabilities relating to environmental contingencies;
- unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;
- capital market conditions, including their effect on the fair value of pension assets and on pension and other postretirement benefit costs;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and
- legal and administrative proceedings and settlements.

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

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity price and supply risk, weather risk, and interest rate risk (see Part II, Item 7A. in the 2006 Form 10-K, Note 8, above, and Part II, Item 1A., Risk Factors, below).

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion and other factors that affect short-term supply and demand. Commodity-price financial swap and option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed or capped prices. These financial hedge contracts are generally included in our annual PGA filing, subject to a regulatory prudence review. At September 30, 2007 and 2006, notional amounts under these financial hedge contracts totaled $357.8 million and $341.9 million, respectively. If all of the financial hedge contracts had been settled on September 30, 2007, a loss of about $33.6 million would have been realized and recorded to a deferred regulatory account (see Note 8, above). We monitor the liquidity of our financial hedge contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our financial hedge contracts settle by October 31, 2008, a portion of which may be extended through October 31, 2009. The $33.6 million unrealized loss is an estimate of future cash flows that are expected to be paid as follows: $30.0 million in the next 12 months and $3.6 million during the following 12 months. The amount realized will change based on market prices at the time contract settlements are fixed.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates with respect to the purchases of natural gas from Canadian suppliers and demand charges from pipelines. At September 30, 2007 and 2006, and December 31, 2006, notional amounts under foreign currency forward contracts totaled $5.7 million, $4.9 million and $5.0 million, respectively. As of September 30, 2007, no foreign currency forward contracts extended beyond September 30, 2008. If all of the foreign currency forward contracts had been settled on September 30, 2007, a gain of $0.4 million would have been realized.

Credit Risk

Credit exposure to financial derivative counterparties. Based on the estimated fair value of existing contracts, our credit position with financial derivative counterparties relating to commodity hedge contracts was a negative $33.6 million at September 30, 2007. Our Financial Derivatives Policy requires counterparties to have a minimum investment grade credit rating at the time the derivative instrument is entered into, and the policy specifies credit limits on contract volumes and duration based on each counterparty s credit rating. A negative position represents the net amount we would owe financial counterparties if all positions were settled at that date. In certain derivative agreements with our financial counterparties, we are required to post cash collateral if the negative amount exceeds an agreed upon credit limit. During each of the periods presented below, we were under the credit limits with all financial counterparties and, therefore, we were not required to post collateral. We also determined that the negative amounts would continue to have been under the credit limits for each counterparty even if the market prices for natural gas were to decline by 20 percent.

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The following table summarizes our credit position, 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, 2007**	**Sept. 30, 2006**	**Dec. 31, 2006**
AAA/Aaa	$ (4,206)	$	$
AA/Aa	(29,346)	(29,122)	(40,955)
A/A			
BBB/Baa			
Total	$ (33,552)	$ (29,122)	$ (40,955)

Interest Rate Risk

We are exposed to interest rate risk associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, locks, options and other hedge products, to manage and mitigate interest rate exposure. At September 30, 2007 and 2006 and December 31, 2006, we had no variable-rate long-term debt and no financial derivative instruments to hedge interest rates. In October 2007, we entered into a $50 million forward starting interest rate swap contract to hedge the interest rate exposure related to long-term debt which is expected to be issued in 2008.

Holders of certain long-term debt have put options that, if exercised, would accelerate the amount of long-term debt maturities by $20 million in 2008 and 2009.

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures
As of September 30, 2007, the principal executive officer and principal financial officer of Northwest Natural Gas Company (NW Natural) have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by us and included in our reports filed with the Securities and Exchange Commission (Commission) under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Commission s rules and forms and are also effective to ensure that information required to be disclosed by us and included in our reports filed with or furnished to the Commission under the Exchange Act is accumulated and communicated to our management as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting
Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f). There have been no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

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

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2006 which could materially affect our business, financial condition or results of operations. The risks described in the 2006 Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our financial condition, results of operations or cash flows.

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, 2007 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [2]
Balance forward			1,670,600	$ 37,727,898
07/01/07 - 07/31/07	919	$ 45.73	234,928	(10,788,993)
08/01/07 - 08/30/07	20,428	$ 44.73		
09/01/07 - 09/30/07	1,651	$ 44.58		
Total	22,998	$ 44.76	1,905,528	$ 26,938,905

(1) During the quarter ended September 30, 2007, 21,671 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 1,327 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended September 30, 2007, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of NW Natural s common stock through a repurchase program that has been extended annually. The purchases are made in the open market or through privately negotiated transactions. In April 2006, the Board increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. In April 2007, the Board extended the program through May 31, 2008 and increased the authorization from 2.6 million shares to 2.8 million shares and increased the dollar limit from $85 million to $100 million. During the three

months ended September 30, 2007, 234,928 shares of our common stock were purchased pursuant to this program. Since the program s inception through September 30, 2007, we have repurchased 1,905,528 shares of common stock at a total cost of $73.1 million.

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On June 29, 2007, we entered into a Stock Purchase Plan Engagement Agreement with our broker in order to establish a trading plan for our repurchase program that qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Exchange Act. That agreement expired on August 3, 2007. On September 24, 2007, we entered into a new Stock Purchase Plan Engagement Agreement with our broker to establish a trading plan for our repurchase program that also qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Exchange Act.

Item 5. OTHER INFORMATION

NNG Financial Corporation, a wholly-owned subsidiary of NW Natural, has held ownership interests ranging from approximately 25 to 41 percent in two wind power electric generation projects located in California. On October 29, 2007, NNG Financial Corporation sold its limited partnership interests in the two projects to the majority partner for an aggregate total of $2.1 million, plus payments for retained cash.

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 8, 2007

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

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

September 30, 2007

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