NORTHWEST NATURAL GAS CO
Form 10-Q
August 03, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2006

OR

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

Commission File No. 1-15973

NORTHWEST NATURAL GAS COMPANY

(Exact name of registrant as specified in its charter)

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

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

(Address of principal executive offices) (Zip Code)

Registrant s Telephone Number, including area code: (503) 226-4211

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

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

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

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

At July 31, 2006, 27,548,346 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

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NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended June 30, 2006

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Income

(Unaudited)

Thousands, except per share amounts	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Operating revenues:				
Gross operating revenues	$ 170,979	$ 153,667	$ 561,370	$ 462,444
Less: Cost of sales	105,036	92,425	360,435	273,033
Revenue taxes	4,196	3,593	13,724	10,776
Net operating revenues	61,747	57,649	187,211	178,635
Operating expenses:				
Operations and maintenance	27,909	26,981	56,156	54,176
General taxes	6,066	5,210	13,639	11,980
Depreciation and amortization	15,962	15,312	31,792	30,507
Total operating expenses	49,937	47,503	101,587	96,663
Income from operations	11,810	10,146	85,624	81,972
Other income and expense net	410	405	928	470
Interest charges - net of amounts capitalized	9,184	8,906	19,039	18,034
Income before income taxes	3,036	1,645	67,513	64,408
Income tax expense	1,042	505	24,486	23,381
Net income	$ 1,994	$ 1,140	$ 43,027	$ 41,027
Average common shares outstanding:				
Basic	27,563	27,555	27,574	27,568
Diluted	27,611	27,834	27,621	27,841
Earnings per share of common stock:				
Basic	$ 0.07	$ 0.04	$ 1.56	$ 1.49
Diluted	$ 0.07	$ 0.04	$ 1.56	$ 1.48

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	**June 30, 2006 (Unaudited)**	**June 30, 2005 (Unaudited)**	**Dec. 31, 2005**
Assets:			
Plant and property:			
Utility plant	$ 1,914,301	$ 1,835,326	$ 1,875,444
Less accumulated depreciation	557,632	523,518	536,867
Utility plant net	1,356,669	1,311,808	1,338,577
Non-utility property	41,094	34,862	40,836
Less accumulated depreciation and amortization	6,452	5,581	5,990
Non-utility property net	34,642	29,281	34,846
Total plant and property	1,391,311	1,341,089	1,373,423
Other investments	54,962	57,978	58,451
Current assets:			
Cash and cash equivalents	6,636	40,343	7,143
Accounts receivable	44,782	35,740	84,418
Accrued unbilled revenue	16,657	17,244	81,512
Allowance for uncollectible accounts	(3,814)	(2,521)	(3,067)
Gas inventory	76,667	36,547	77,256
Materials and supplies inventory	9,546	9,295	8,905
Income taxes receivable			13,234
Prepayments and other current assets	47,648	16,048	54,309
Total current assets	198,122	152,696	323,710
Regulatory assets:			
Income tax asset	66,757	65,622	65,843
Deferred environmental costs	21,771	13,175	18,880
Deferred gas costs receivable	8,594	7,958	6,974
Unamortized costs on debt redemptions	6,670	7,097	6,881
Unrealized loss on non-trading derivatives	186		
Other		7,092	
Total regulatory assets	103,978	100,944	98,578
Other assets:			
Fair value of non-trading derivatives	26,926	64,089	178,653
Other	9,448	7,643	9,216
Total other assets	36,374	71,732	187,869

Total assets	$ 1,784,747	$ 1,724,439	$ 2,042,031

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	**June 30, 2006 (Unaudited)**	**June 30, 2005 (Unaudited)**	**Dec. 31, 2005**
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 383,103	$ 87,285	$ 87,334
Premium on common stock		300,074	296,471
Earnings invested in the business	229,684	207,050	205,687
Unearned stock compensation		(756)	(650)
Accumulated other comprehensive income (loss)	(1,911)	(1,818)	(1,911)
Total common stock equity	610,876	591,835	586,931
Long-term debt	492,000	521,500	521,500
Total capitalization	1,102,876	1,113,335	1,108,431
Current liabilities:			
Notes payable	55,800		126,700
Long-term debt due within one year	29,500	27,241	8,000
Accounts payable	76,804	66,472	135,287
Taxes accrued	13,886	8,543	12,725
Interest accrued	2,878	2,953	2,918
Other current and accrued liabilities	36,216	35,312	40,935
Total current liabilities	215,084	140,521	326,565
Regulatory liabilities:			
Accrued asset removal costs	178,272	162,350	169,927
Unrealized gain on non-trading derivatives, net		54,666	171,777
Customer advances	2,113	1,662	1,847
Other	5,744		661
Total regulatory liabilities	186,129	218,678	344,212
Other liabilities:			
Deferred income taxes	220,439	206,666	222,331
Deferred investment tax credits	4,422	5,200	5,069
Fair value of non-trading derivatives	27,398	9,423	6,876
Other	28,399	30,616	28,547
Total other liabilities	280,658	251,905	262,823
Commitments and contingencies (see Note 9)			
Total capitalization and liabilities	$ 1,784,747	$ 1,724,439	$ 2,042,031

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

Thousands	**Six Months Ended June 30, 2006**	**2005**
Operating activities:		
Net income	$ 43,027	$ 41,027
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	31,792	30,507
Deferred income taxes and investment tax credits	(3,453)	(5,762)
Undistributed earnings from equity investments	(59)	(54)
Allowance for funds used during construction	(333)	(201)
Deferred gas costs net	(1,620)	1,593
Gain on sale of non-utility investments		(12)
Contributions to qualified defined benefit pension plans		
Non-cash expenses related to qualified defined benefit pension plans	2,883	2,318
Deferred environmental costs	(3,586)	(805)
Income from life insurance investments	(1,797)	(974)
Other	5,787	(2,925)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	105,238	72,138
Inventories of gas, materials and supplies	(52)	20,635
Income taxes receivable	13,234	15,970
Prepayments and other current assets	2,377	7,383
Accounts payable	(58,483)	(36,006)
Accrued interest and taxes	1,121	(1,643)
Other current and accrued liabilities	(4,719)	1,144
Cash provided by operating activities	131,357	144,333
Investing activities:		
Investment in utility plant	(38,991)	(41,428)
Investment in non-utility property	(236)	(889)
Proceeds from sale of non-utility investments		3,001
Proceeds from life insurance	892	
Other	4,453	679
Cash used in investing activities	(33,882)	(38,637)
Financing activities:		
Common stock issued, net of expenses	1,556	4,669
Common stock repurchased	(1,608)	(4,861)
Long-term debt issued		50,000
Long-term debt retired	(8,000)	
Change in short-term debt	(70,900)	(102,500)
Cash dividend payments on common stock	(19,030)	(17,909)

Cash used in financing activities	(97,982)	(70,601)
Increase (decrease) in cash and cash equivalents	(507)	35,095
Cash and cash equivalents - beginning of period	7,143	5,248
Cash and cash equivalents - end of period	$ 6,636	$ 40,343
Supplemental disclosure of cash flow information:		
Interest paid	$ 19,052	$ 17,796
Income taxes paid	$ 9,520	$ 11,739
Supplemental disclosure of non-cash financing activities:		
Conversions to common stock:		
7-1/4 % Series of Convertible Debentures	$	$ 286

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Capitalization

Thousands	June 30, 2006 (Unaudited)		June 30, 2005 (Unaudited)		Dec. 31, 2005	
Common stock equity:						
Common stock	$ 383,103		$ 87,285		$ 87,334	
Premium on common stock			300,074		296,471	
Earnings invested in the business	229,684		207,050		205,687	
Unearned compensation			(756)		(650)	
Accumulated other comprehensive income (loss)	(1,911)		(1,818)		(1,911)	
Total common stock equity	610,876	55%	591,835	53%	586,931	53%
Long-term debt:						
Medium-Term Notes						
First Mortgage Bonds:						
6.340% Series B due 2005			5,000			
6.380% Series B due 2005			5,000			
6.450% Series B due 2005			5,000			
6.050% Series B due 2006			8,000		8,000	
6.310% Series B due 2007	20,000		20,000		20,000	
6.800% Series B due 2007	9,500		9,500		9,500	
6.500% Series B due 2008	5,000		5,000		5,000	
4.110% Series B due 2010	10,000		10,000		10,000	
7.450% Series B due 2010	25,000		25,000		25,000	
6.665% Series B due 2011	10,000		10,000		10,000	
7.130% Series B due 2012	40,000		40,000		40,000	
8.260% Series B due 2014	10,000		10,000		10,000	
4.700% Series B due 2015	40,000		40,000		40,000	
7.000% Series B due 2017	40,000		40,000		40,000	
6.600% Series B due 2018	22,000		22,000		22,000	
8.310% Series B due 2019	10,000		10,000		10,000	
7.630% Series B due 2019	20,000		20,000		20,000	
9.050% Series A due 2021	10,000		10,000		10,000	
5.620% Series B due 2023	40,000		40,000		40,000	
7.720% Series B due 2025	20,000		20,000		20,000	
6.520% Series B due 2025	10,000		10,000		10,000	
7.050% Series B due 2026	20,000		20,000		20,000	
7.000% Series B due 2027	20,000		20,000		20,000	
6.650% Series B due 2027	20,000		20,000		20,000	
6.650% Series B due 2028	10,000		10,000		10,000	
7.740% Series B due 2030	20,000		20,000		20,000	
7.850% Series B due 2030	10,000		10,000		10,000	
5.820% Series B due 2032	30,000		30,000		30,000	
5.660% Series B due 2033	40,000		40,000		40,000	
5.250% Series B due 2035	10,000		10,000		10,000	
Convertible Debentures						
7-1/4% Series due 2012			4,241			
	521,500		548,741		529,500	
Less long-term debt due within one year	29,500		27,241		8,000	

Total long-term debt	492,000	45%	521,500	47%	521,500	47%
Total capitalization	$ 1,102,876	100%	$ 1,113,335	100%	$ 1,108,431	100%

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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), a regulated utility, and its non-regulated wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation).

The information presented in the interim consolidated financial statements is unaudited, but includes all material adjustments, including normal recurring accruals, that management considers necessary for a fair statement of the results for each period reported. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2005 Annual Report on Form 10-K (2005 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 amounts from prior years have been reclassified to conform, for comparison purposes, with the current financial statement presentation. The current year s presentation of the Consolidated Statements of Income includes the reclassification of revenue taxes as a component of net operating revenues. Revenue taxes are expenses primarily related to the utility s franchise agreements and are based on gross operating revenues. Since revenue taxes are a direct cost of utility sales, the financial statement classification was changed to improve the presentation of net operating revenues and operating expenses. In prior years, revenue taxes were included under operating expenses as part of taxes other than income taxes. The reclassifications had no impact on the prior year s income from operations or net income.

2. New Accounting Standards

Adopted Standards

Share Based Payment. Effective Jan. 1, 2006, we adopted Statement of Financial Accounting Standards (SFAS) No. 123R, Share Based Payment, using the Modified Prospective Application method without restatement of prior periods. Prior to implementation of SFAS No. 123R, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under this method, we began to amortize compensation cost for the remaining portion of outstanding awards for which the requisite service was not yet rendered at Jan. 1, 2006. Compensation cost for these awards was based on the fair value of the awards at the grant date which was determined under the intrinsic value method. We determine the fair value of and account for awards that are granted, modified or settled after Jan. 1, 2006 in accordance with SFAS No. 123R. The adoption of SFAS No. 123R did not have a material impact on our financial condition, results of operations or cash flows. See Note 4 for a discussion of stock-based compensation.

Accounting for Changes and Error Corrections. Effective Jan. 1, 2006, we adopted SFAS No. 154, Accounting for Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3, which provides guidance on the accounting for and reporting of accounting changes and error corrections. The statement requires retrospective application to prior periods financial statements of changes in accounting principles, unless it is impracticable

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to determine the period-specific effects or the cumulative effect of the change. The guidance provided in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements remains unchanged and requires the restatement of previously issued financial statements. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after Dec. 15, 2005. The adoption of SFAS No. 154 did not have a material impact upon NW Natural s financial condition, results of operation or cash flows.

Inventory Costs. Effective Jan. 1, 2006, we adopted SFAS No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4, which amends the guidance on inventory pricing to require that abnormal amounts of idle facility expense, freight, handling costs and wasted material be charged to current period expense rather than capitalized as inventory costs. The adoption of SFAS No. 151 did not have a material impact on NW Natural s financial condition, results of operations or cash flows.

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the Financial Accounting Standards Board s (FASB) Emerging Issues Task Force (EITF) reached a final consensus on Issue 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. EITF 04-13 requires that two or more legally separate exchange transactions with the same counterparty be combined and considered a single arrangement for purposes of applying APB Opinion No. 29, Accounting for Nonmonetary Transactions, when the transactions are entered into in contemplation of one another. EITF 04-13 is effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006. Adoption of this standard did not have a material impact on NW Natural s financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

Accounting for Certain Hybrid Instruments. In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Instruments, which amends SFAS Nos. 133 and 140. 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. The statement is effective for all financial instruments acquired or issued after Jan. 1, 2007. We are in the process of evaluating the effect of the adoption and implementation of SFAS No. 155, which is not expected to have a material impact on our financial condition, results of operation or cash flows.

Variable Interest Entities. In April 2006, the FASB issued a staff position (FSP) interpreting variable interest entities (VIE) under FASB Interpretation No. (FIN) 46(R)-6, Determining the Variability to be Considered in Applying FIN 46(R). This staff position emphasizes that preparers should use a by design approach in determining whether an interest is variable. A by design approach includes evaluating whether an interest is variable based on a thorough understanding of the design of the potential VIE, including the nature of the risks that the potential VIE was designed to create and pass along to interest holders in the entity. Consolidation of a VIE by the primary beneficiary is required if it is determined that the VIE does not effectively disperse risks among the parties involved. FSP No. FIN 46(R)-6 must be applied prospectively to all entities with which the company first becomes involved and to all entities previously required to be analyzed under FIN 46(R) when a reconsideration event has occurred effective on or after July 1, 2006. We are in the process of evaluating the effect of adoption and implementation of FSP No. FIN 46(R)-6, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

Accounting for Uncertainty in Income Taxes. In July 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes, an Interpretation of FASB

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Statement No. 109, (FIN 48). FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken in a tax return. We must determine whether it is more-likely-than-not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. Once it is determined that a position meets the more-likely-than-not recognition threshold, the position is measured to determine the amount of benefit to recognize in the financial statements. FIN 48 applies to all tax positions related to income taxes subject to SFAS No. 109, Accounting for Income Taxes. The interpretation scopes out income tax positions related to SFAS No. 5, Accounting for Contingencies. FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. We do not anticipate that the adoption of this statement will have a material effect on our financial position or results of operations.

3. Capital Stock

At NW Natural s Annual Meeting held on May 25, 2006, the shareholders approved the Restated Articles of Incorporation, which, among other things, included an amendment, effective May 31, 2006, to eliminate the par value of NW Natural s common stock. As a result, NW Natural s common stock and premium on common stock account balances are now reflected on the balance sheet as common stock.

In addition, the shareholders approved an amendment to the Employee Stock Purchase Plan that reserved an additional 200,000 shares of common stock for issuance under the plan.

4. Stock-Based Compensation

Effective Jan. 1, 2006, we adopted SFAS No. 123R, Share Based Payment, to account for all stock-based compensation plans. 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. See Part II, Item 8., Note 4, in the 2005 Form 10-K for a discussion of NW Natural s stock-based compensation plans.

Long-Term Incentive Plan. A total of 500,000 shares of NW Natural s common stock has been authorized for awards under the terms of the LTIP as stock bonus, restricted stock or performance-based stock awards. At June 30, 2006, performance-based awards on 105,000 shares, based on target, were outstanding, a restricted stock award for 5,000 shares was outstanding, and the remaining 390,000 shares were available for future grants.

Performance-based Stock Awards. At June 30, 2006, the aggregate number of performance-based shares awarded and outstanding under NW Natural s LTIP at the threshold, target and maximum levels were as follows:

Year Awarded	Performance Period	Threshold	Target	Maximum
2004	2004-06	6,750	27,000	54,000
2005	2005-07	8,750	35,000	70,000
2006	2006-08	10,750	43,000	86,000
Total		26,250	105,000	210,000

For each of the performance periods shown above, awards will be based on total shareholder return relative to a peer group of gas distribution companies over the three-year performance period and on performance results relative to our core and non-core strategies. For awards granted prior to Jan. 1, 2006, we recognize compensation expense and liability for the LTIP awards based on performance levels achieved, and expected to be achieved, and the estimated market value of the common stock as of the distribution date. For awards granted on or after Jan. 1, 2006, we recognize compensation expense in accordance with SFAS No. 123R, based on performance levels achieved and an estimated fair value using a lattice valuation model. For the quarter and six months ended June 30, 2006, the amount accrued and expensed as compensation under the three LTIP grants was negligible. On a cumulative basis, $0.7 million, $0.6 million and a negligible amount have been accrued for the 2004-06, 2005-07 and 2006-08 performance periods, respectively.

Restricted Stock Awards. Restricted stock awards also have been granted under the LTIP. A restricted stock award consisting of 5,000 shares was granted in 2004, which will vest ratably over the period 2005-09.

Restated Stock Option Plan. We have reserved a total of 2,400,000 shares of Common Stock for issuance under the Restated SOP. At June 30, 2006, options on 1,134,400 shares were available for grant and options to purchase 388,750 shares were outstanding. Options are granted with an exercise price equal to the market value of the common stock at the date of grant, have 10-year terms and vest ratably over a three- or four-year period following the date of grant. Shares issued under the Restated SOP upon the exercise of stock options are original issue shares. The fair value of our stock-based awards were estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

	2006	2005
Risk-free interest rate	4.5%	4.2%
Expected life (in years)	6.2	7.0
Expected market price volatility factor	22.8%	24.6%
Expected dividend yield	4.0%	3.6%

The simplified formula for plain vanilla options was utilized to determine the expected life as defined and permitted by Staff Accounting Bulletin No. 107. The risk-free interest rate was based on the implied yield currently available on U.S. Treasury zero-coupon issues with a life equal to the expected life of the options. Historical data was employed in order to estimate the volatility factor, measured on a daily basis, for a period equal to the duration of the expected life of the option awards. The dividend yield was based on management s current estimate for dividend payout at the time of grant. A forfeiture rate of 3 percent was applied to the calculation of compensation expense based on historical experience.

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The following table presents the effect on net income and earnings per share of outstanding stock options and stock awards:

Pro Forma Effect of Stock-Based Options and ESPP:	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands, except per share amounts	**2006**	**2005**	**2006**	**2005**
Net income as reported	N/A*	$ 1,140	N/A*	$ 41,027
Add: Actual stock-based compensation expense included in reported net income under SFAS No. 123R, net of related tax effects				
Deduct: Pro forma stock-based compensation expense determined under the fair value based method net of related tax effects		(92)		(183)
Pro forma earnings applicable to common stock - basic		1,048		40,844
Debenture interest less taxes		47		94
Pro-forma earnings applicable to common stock - diluted		$ 1,095		$ 40,938
Basic earnings per share				
As reported		$ 0.04		$ 1.49
Pro forma		$ 0.04		$ 1.48
Diluted earnings per share				
As reported		$ 0.04		$ 1.48
Pro forma		$ 0.04		$ 1.47

* During 2006, we implemented SFAS No. 123R and, therefore, pro forma is as reported.

Summarized information for stock option grants is as follows:

	Option Shares	Price per Share Range	Weighted-Average Exercise Price
Balance Outstanding at Dec. 31, 2005	308,500	$20.25-38.30	$ 29.26
Granted	97,800	34.29	34.29
Exercised	(15,150)	20.25-31.34	25.97
Expired	(2,400)	31.34	32.82
Balance Outstanding at June 30, 2006	388,750	$20.25-38.30	$ 30.63
Exercisable at Dec. 31, 2005	189,500	$20.25-32.02	$ 27.63
Exercisable at June 30, 2006	230,850	$20.25-32.02	$ 28.66

The weighted-average grant-date fair value of equity awards granted during 2005 and 2006 was $7.85 and $6.29, respectively. By Dec. 31, 2006, an additional 3,000 shares will vest for a total of 233,850 exercisable shares at year-end, assuming no forfeitures.

During the three and six months ended June 30, 2006, pre-tax compensation expense amounted to $0.2 million and $0.4 million, respectively, relating to options granted under the Restated SOP. This expense was recognized in operations and maintenance expense under the fair value method in accordance with SFAS No. 123R. In addition, $0.1 million of pre-tax compensation expense related to the ESPP was recognized. As of June 30, 2006, 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 2009.

In the six months ended June 30, 2006, 15,150 option shares were exercised with a total intrinsic value of $0.1 million. Cash of $0.4 million was received for these exercises, and a negligible

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related tax benefit was realized. The total intrinsic value of options exercised in the first six months of 2005 was $1.0 million, and the total fair value of options that vested in the first six months of 2006 and 2005 was $0.3 million and $0.4 million, respectively.

The following table summarizes additional information about stock options outstanding and exercisable at June 30, 2006:

Range of Exercise Prices	Outstanding Stock Options	Outstanding (In millions) Aggregate Intrinsic Value	Exercisable Stock Options	Exercisable (In millions) Aggregate Intrinsic Value	Weighted-Average Exercise Price	Weighted-Average Remaining Life in Years
$20.25 - 38.30	388,750	$ 1.6	230,850	$ 1.4	$ 28.66	6.1

5. Long-Term Debt

In June 2006, NW Natural redeemed $8.0 million of secured 6.05% Series B Medium-Term Notes, at maturity.

6. Use of Derivative Instruments

NW Natural enters into forward contracts and other related financial transactions for the purchase of natural gas 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). NW Natural utilizes derivative financial instruments to manage commodity prices related to natural gas supply requirements (see Part II, Item 8., Note 11, in the 2005 Form 10-K).

At June 30, 2006 and 2005, unrealized gains or losses from mark-to-market valuations of our derivative instruments were primarily reported as regulatory liabilities or regulatory assets because regulatory mechanisms provide for the realized gains or losses at settlement to be included in utility gas costs, pursuant to regulatory deferral treatment. The estimated fair values for unrealized gains and losses on derivative instruments outstanding, determined using a discounted cash flow model, were as follows:

Thousands	June 30, 2006	June 30, 2005	Dec. 31, 2005
Fair Value Gain (Loss):			
Natural gas commodity-based derivative instruments:			
Fixed-price financial swaps	$ 1,853	$ 62,464	$ 173,790
Fixed-price financial call options			1,871
Indexed-price physical supply	(2,571)	(7,887)	(5,454)
Fixed-price physical supply			820
Physical supply contracts with embedded options	335	43	567
Foreign currency forward purchases	197	46	183
Total	$ (186)	$ 54,666	$ 171,777

In the second quarter of 2006, NW Natural realized net losses of $10.5 million from the settlement of fixed-price financial swap contracts, which were recorded as decreases to the cost of gas. Realized losses were offset by lower gas purchase costs from underlying floating rate physical supply contracts. The exchange rate in foreign currency forward contracts is included in cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts.

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As of June 30, 2006, all natural gas commodity price swap contracts mature no later than Oct. 31, 2008.

7. Segment Information

Our primary business segment, Utility, consists of the distribution and sale of natural gas. Another segment, Interstate Gas Storage, represents natural gas storage services provided to interstate and intrastate customers and asset optimization activities performed by an unaffiliated energy marketing company primarily through the use of commodity transactions and releases of temporarily unused portions of NW Natural s upstream pipeline transportation capacity and gas storage capacity (see Part II, Item 8., Note 2, in the 2005 Form 10-K). The remaining segment, Other, primarily consists of non-utility operating activities and non-regulated investments.

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

	Three Months Ended June 30,				Six Months Ended June 30,			
Thousands	Utility	Interstate Gas Storage	Other	Total	Utility	Interstate Gas Storage	Other	Total
2006								
Net operating revenues	$ 58,047	$ 3,671	$ 29	$ 61,747	$ 180,391	$ 6,750	$ 70	$ 187,211
Depreciation and amortization	15,742	220		15,962	31,352	440		31,792
Income (loss) from operations	8,992	3,249	(431)	11,810	80,114	5,933	(423)	85,624
Income from financial investments	414		109	523	1,797		59	1,856
Net income (loss)	214	1,817	(37)	1,994	39,666	3,266	95	43,027
Total assets at June 30, 2006	1,737,026	36,084	11,637	1,784,747	1,737,026	36,084	11,637	1,784,747
2005								
Net operating revenues	$ 55,676	$ 1,952	$ 21	$ 57,649	$ 174,612	$ 3,981	$ 42	$ 178,635
Depreciation and amortization	15,149	163		15,312	30,180	327		30,507
Income (loss) from operations	8,559	1,587		10,146	78,727	3,280	(35)	81,972
Income from financial investments	506		208	714	974		71	1,045
Net income	12	844	284	1,140	38,856	1,742	429	41,027
Total assets at June 30, 2005	1,682,429	29,424	12,586	1,724,439	1,682,429	29,424	12,586	1,724,439

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8. Pension and Other Postretirement Benefits

Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the qualified and non-qualified pension plans and other postretirement benefit plans. See Part II, Item 8., Note 7, in the 2005 Form 10-K for a discussion of the assumptions used in measuring these costs and benefit obligations.

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended June 30,			
Thousands	**2006**	**2005**	**2006**	**2005**
Service cost	$ 1,961	$ 1,589	$ 138	$ 114
Interest cost	3,758	3,263	283	308
Special termination benefits		63		
Expected return on plan assets	(4,403)	(3,531)		
Amortization of transition obligation			103	103
Amortization of prior service cost	245	223	49	
Recognized actuarial loss	916	481		72
Net periodic benefit cost	$ 2,477	$ 2,088	$ 573	$ 597

	Pension Benefits		Other Postretirement Benefits	
	Six Months Ended June 30,			
Thousands	**2006**	**2005**	**2006**	**2005**
Service cost	$ 3,922	$ 3,177	$ 275	$ 228
Interest cost	7,516	6,526	566	616
Special termination benefits		126		
Expected return on plan assets	(8,807)	(7,061)		
Amortization of transition obligation			206	206
Amortization of prior service cost	490	446	98	
Recognized actuarial loss	1,833	963		144
Net periodic benefit cost	$ 4,954	$ 4,177	$ 1,145	$ 1,194

Employer Contributions

We are not required to make cash contributions to our qualified non-contributory defined benefit plans in 2006, but cash contributions in the form of ongoing benefit payments will be required for the unfunded non-qualified supplemental pension plans and other postretirement benefit plans in 2006. See Part II, Item 8., Note 7, in the 2005 Form 10-K for a discussion of future payments.

9. Commitments and Contingencies

Environmental Matters

We own, or have previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study the extent of potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the

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probabilities thereof, cannot be reasonably estimated. We regularly review our remediation liability for each site where we may be exposed to remediation responsibilities. The costs of environmental remediation are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course of the effort. In certain cases, in addition to NW Natural, there are a number of other potentially responsible parties, each of which, in proceedings and negotiations with other potentially responsible parties and regulators, may influence the course of the remediation effort. The allocation of liabilities among the potentially responsible parties is often subject to dispute and highly uncertain. The events giving rise to environmental liabilities often occurred many decades ago, which complicates the determination of allocating liabilities among potentially responsible parties. Site investigations and remediation efforts often develop slowly over many years. To the extent reasonably estimable, we estimate the costs of environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a more likely estimate within this range of probable cost, we record the liability at the lower end of this range. It is likely that changes in these estimates will occur throughout the remediation process for each of these sites due to uncertainty concerning our responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. The status of each of the sites currently under investigation is provided below. Also, see Part II, Item 8., Note 12, in the 2005 Form 10-K for a description of these properties and further discussion.

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). We have been investigating the Gasco site 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 the second quarter of 2006, we accrued an additional $2.1 million to be used for the upgrade of the water treatment system in conjunction with source control, replacement of a well, ongoing consultant and investigation fees for in-river groundwater and source control studies and to cover cost estimates of remedial alternatives identified in the Feasibility Scoping Plan and Ecological and Human Health risk assessment for the most contaminated portion of the site. The liability balance at June 30, 2006 is $2.6 million, which is at the low end of the probable and reasonably estimable liability range. We are not able to estimate the high end of a liability range.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We have agreed to an addendum to the Voluntary Clean-up Agreement with the ODEQ, which will require additional investigation of manufactured gas plant waste on the Siltronic site. Since the scope of work is unknown, there is not enough information to reasonably estimate the additional liabilities.

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 (the 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. 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). In the second quarter of 2006, we increased the liability by $0.2 million to $1.6 million in total for our current estimate of liability related to the RI/FS, consultant fees, technical work, and state settlement agreement. Information is not sufficient to

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reasonably estimate additional liabilities, if any, or the range of potential liabilities, for environmental remediation and monitoring after the RI/FS work plan is completed, except for the early action removal of a tar deposit in the river sediments discussed below.

In April 2004, we entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the Willamette River sediments adjacent to the Gasco site. The removal of the tar deposit in the Portland Harbor was completed in October 2005, and in November 2005, the EPA approved the completed project. In the second quarter of 2006, we increased the liability by $0.2 million to $1.4 million for our current remaining cost estimate related to the tar deposit, including oversight, consultant and legal fees and ongoing monitoring. To date, $8.8 million has been spent for work related to the removal of the tar deposit.

Oregon Steel Mills site. See Legal Proceedings, below.

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. The authorization, which has been extended through January 2007, allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. In April 2006, the OPUC authorized us to accrue interest on deferred balances effective Jan. 27, 2006, subject to an annual demonstration to the OPUC that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. As of June 30, 2006, we have paid a cumulative total of $16.0 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, we have recognized a total of $26.6 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $20.9 million has been spent to-date and $5.7 million is reported as an outstanding liability. During the second quarter of 2006, we increased regulatory assets by $2.6 million for additional environmental cost estimates related to authorized sites, and at June 30, 2006, we had a total environmental regulatory asset of $21.7 million, which includes $16.0 million of total expenditures to date and accruals for additional estimated costs of $5.7 million. We believe the recovery of these costs is probable through the regulatory process after first pursuing recovery of costs from insurance. We also have an insurance receivable of $1.1 million, which is not included in the regulatory asset amount. 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. We consider insurance recovery 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 recent Oregon legislation that allows an insured party to seek recovery of all sums from one insurance company. We have notified the insurance companies but have not yet filed claims for recovery nor have the insurance companies approved or denied coverage of these claims.

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 and in Part II, Item 8., Note 12, in the 2005 Form 10-K, cannot be predicted with certainty, we do not expect that the ultimate disposition of these matters will have a materially adverse effect on our financial condition, results of operations or cash flows.

Georgia-Pacific Corporation vs. Northwest Natural Gas Company. On Feb. 3, 2006, Georgia-Pacific Corporation filed suit against NW Natural (*Georgia-Pacific Corporation v. Northwest Natural Gas Company*, Case No. CV06-151-PK, United States District Court, District of

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Oregon), alleging that we offered to sell natural gas to Georgia-Pacific under the interruptible sales service provisions of Rate Schedule 32 at a commodity rate set at our Weighted Average Cost of Gas (WACOG). Georgia-Pacific further alleged that we accepted this offer and that we failed to perform as promised when, in October 2005, we notified Georgia-Pacific that we would have to charge Georgia-Pacific the incremental costs of acquiring gas on the open market. Georgia-Pacific also alleged breach of contract, promissory estoppel, fraudulent misrepresentation and breach of the duty of good faith and fair dealing.

On Feb. 23, 2006, we filed a motion for summary judgment on all claims. On June 30, 2006, an order was issued by the U.S. District Court for the District of Oregon dismissing the lawsuit with prejudice and denying all pending motions, if any, as moot. On July 27, 2006, Georgia-Pacific appealed this ruling to the Ninth Circuit Court of Appeals. We do not expect the outcome of this appeal to have a material effect on our financial condition or results of operations.

Independent Backhoe Operator Action. Since May 2004 five lawsuits have been filed against the Company by 11 independent backhoe operators who performed backhoe services for the Company under contract. These five lawsuits have been consolidated into one consolidated case, *Law and Zuehlke, et. al. v. Northwest Natural Gas Co.,* CV-04-728-KI. The consolidated case consolidates the following cases previously reported: *Kerry Law and Arnold Zuehlke, on behalf of themselves and all others similarly situated v. Northwest Natural Gas Company* (filed May 28, 2004 U.S. Dist. Ct. D. Or. Case No. CV-04-728-KI), *Ike Whittlesey, C.G. Nick Courtney, Mark Parrish, John J. Shooter, Roger Whittlesey and Philip Courtney v. Northwest Natural* (filed February 18, 2005 U.S. Dist. Ct. D. Or. Case No. CV-05-241-KI), *Phillip Courtney v. Northwest Natural* (filed April 12, 2005 U.S. Dist. Ct. D. Or., Case No. CV-05-507-BR), and *Kenneth Holtmann et. al. v. Northwest Natural* (filed May 20, 2005 U.S. Dist. Ct. D. Or. Case No. 05-CV-00724-BR). The consolidated case also includes a fifth lawsuit filed on January 23, 2006, *Larry L. Luethe v. Northwest Natural* (U.S. Dist. Ct. D. Or. Case No. CV-06-098-MO).

Plaintiffs in the consolidated case are or have been independent backhoe operators who performed services for the Company under contract. Plaintiffs allege violation of the Fair Labor Standards Act for failure to pay overtime and also assert state wage and hour claims. Plaintiffs claim that they should have been considered employees, and seek overtime wages and interest in amounts to be determined, liquidated damages equal to the overtime award, civil penalties and attorneys fees and costs. Additionally, with the exception of the plaintiff in *Larry L. Luethe v. Northwest Natural,* plaintiffs allege that the failure to classify them as employees constituted a breach of contract and a tort under and with respect to certain unspecified employee benefits plans, programs and agreements. With the exception of the plaintiff in *Larry L. Luethe v. Northwest Natural,* plaintiffs seek an unspecified amount of damages for the value of what they would have received under these employee benefit plans if they had been classified as employees. We expect that the plaintiff in *Larry L. Luethe v. Northwest Natural* will amend his complaint to include this breach of contract and tort claims for unspecified damages.

In October 2005, the court granted the Company s motion to stay plaintiffs claims pending exhaustion of the administrative review process with regard to each of the plans under which plaintiffs allege that they would have been eligible to receive benefits. The litigation is still stayed pending plaintiffs exhaustion of the administrative review process. There is insufficient information at this time to reasonably estimate the range of liability, if any, from these claims. We will vigorously contest these claims and do not expect the outcome of this litigation to have a material effect on our results of operations or financial condition.

Oregon Steel Mills site. In 2004, we were 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 NW Natural s predecessor, Portland Gas & Coke Company, and ten other third-party defendants

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disposed of waste oil in a 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 NW Natural 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 do not expect that the ultimate disposition of this matter will have a materially adverse effect on our financial condition, results of operations or cash flows.

10. Comprehensive Income

For the three and six months ended June 30, 2006 and 2005, reported net income was equivalent to total comprehensive income. Items that are excluded from net income and charged directly to common stock equity are accumulated in other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss included in total common stock equity is $1.9 million at June 30, 2006, which is related to our minimum pension liability (see Consolidated Statements of Capitalization, above).

11. Subsequent Event

On July 26, 2006, we granted a restricted stock award under our LTIP consisting of 6,500 shares, which will vest ratably on March 1, 2007, 2008 and 2009 (see Note 4).

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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

Northwest Natural Gas Company (NW Natural) is a natural gas services company primarily engaged in the distribution of natural gas to residential, commercial and industrial customers, operating as a regulated utility business in Oregon and southwest Washington. The utility is our largest business segment with approximately 98 percent of consolidated total assets. Factors critical to the success of the utility include maintaining a safe and reliable distribution system, acquiring and distributing natural gas supplies and services at a competitive price, and being able to recover the operating and capital costs in the rates charged to customers.

NW Natural also is engaged in the delivery of interstate and intrastate gas storage services, operating as a non-utility business segment principally regulated by the Federal Energy Regulatory Commission (FERC). This segment, which represents approximately 2 percent of consolidated total assets, provides services to large customers using storage and transportation capacity and asset optimization services provided under an agreement with an independent energy marketing company. Factors critical to the success of this segment include being able to develop additional storage capacity at competitive market prices and being able to continue asset optimization services using core utility assets under regulatory sharing agreements.

In addition to the utility and interstate gas storage business segments, the consolidated financial statements include the accounts of a wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation), and other non-regulated activities, which together are referred to in this report as our Other business segment (see Note 7).

The following is management s assessment of NW Natural s financial condition including the principal factors that affect our results of operations. The discussion refers to our consolidated activities for the three and six months ended June 30, 2006 and 2005. Unless otherwise indicated, references in this discussion to Notes are to the notes to the consolidated financial statements in this report. 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 to earnings per share in this report are on the basis of diluted shares, except where noted otherwise (see Part II, Item 8., Note 1, Earnings Per Share, in the 2005 Form 10-K).

Issues and Challenges

There are a number of factors that directly affect our consolidated financial condition and results of operations. The most significant factor we face in the near term is the impact of higher gas prices. While wholesale gas prices had declined in recent months, the current forward market price for natural gas remains higher than the levels currently embedded in our utility customers rates, which means our customers rates are likely to increase this fall. The majority of our gas supplies come from Alberta and British Columbia, while the remainder comes from the U.S. Rocky Mountain region. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but further price increases could change our competitive advantage and our customers preference for natural gas. If higher gas prices persist, it could affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses energy needs to alternative fuel sources.

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Other issues and challenges we could face in the future include unpredictable weather conditions, adverse regulatory actions or policy changes, managing gas supplies, storage and transportation capacity, managing customer growth, maintaining a competitive advantage, managing environmental risks, and managing interest rate and credit risks. For a more complete discussion of these and other risks, see Part II, Item 7., Issues, Challenges and Performance Measures, and Part I, Item 1A., Risk Factors, in the 2005 Form 10-K.

To address some of the challenges, we recently initiated a company-wide restructuring of operations with the goal of significantly improving work processes, reducing operating expenses and capital costs, and continuing to strive for excellence in customer service. Our focus has been on developing initiatives to achieve long-term strategic targets. Implementation of these initiatives will involve:

- developing a more integrated operations model;
- further enhancing our ability to add customers profitably;
- implementing more standardization in all work processes;
- centralizing resource planning, scheduling, quality assurance and performance management activities;
- outsourcing work that is not core to our safety, reliability, regulatory compliance or customer service activities;
- increasing the integration and efficiency of information technology systems; and
- maintaining a strong community presence while reorganizing district operations.

This improved operations model is expected to be implemented over the next several years and to include workforce reductions. These reductions are expected to be accomplished by primarily focusing on a combination of normal attrition and voluntary severance packages. Accordingly, we expect to incur costs of about $1.5 million to $2.0 million in the fourth quarter of 2006 related to a workforce reduction of an estimated 50-100 people, which we expect to largely offset by a combination of cost reductions and gains from non-core asset sales.

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 using different assumptions.

Our most critical estimates or judgments involve regulatory cost recovery, unbilled revenues, derivative instruments, pension assumptions, income taxes and environmental and other contingencies (see Part II, Item 7., Application of Critical Accounting Policies and Estimates, in the 2005 Form 10-K). There have been no material changes to the information provided in our 2005 Form 10-K with respect to the application of critical accounting policies and estimates. Management has discussed its 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.

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Earnings and Dividends

Three months ended June 30, 2006 compared to June 30, 2005:

Net income was $2.0 million, or 7 cents a share, compared to $1.1 million, or 4 cents a share, in the same period in 2005. The increase was primarily due to improved results from our utility and interstate gas storage segments. NW Natural s utility operations contributed $0.2 million, or 1 cent a share, to earnings in the second quarter of 2006, compared to negligible earnings in 2005. Net income from utility operations is typically low during the second quarter due to the reduced use of natural gas in the spring and early summer. Interstate gas storage operations contributed $1.8 million to earnings in the second quarter of 2006, or 6 cents a share, compared to $0.8 million, or 3 cents a share, in the same period in 2005. Other non-utility activities resulted in a negligible loss for the quarter compared to a gain of $0.3 million, or 1 cent a share, in 2005.

Primary factors affecting second quarter earnings this year over last year include:

- an increase in utility margin from residential and commercial customers of $1.0 million, or 2 percent, primarily resulting from a net increase of 19,973 customers, reflecting a 3.3 percent annual customer growth rate, and the impact of our weather normalization and decoupling mechanisms, which largely mitigated the negative effects of warmer weather and customer conservation;

- an increase in utility margin of $1.7 million from gas purchase savings under the regulatory Purchased Gas Adjustment (PGA) incentive mechanism;

- an increase in interstate gas storage margin of $1.7 million reflecting stronger demand for storage services and increased optimization activity using available core gas supply, storage and transportation capacity;

- an increase in total operating expenses of $2.4 million, or 5 percent, reflecting a combination of higher operation and maintenance expenses, general taxes and depreciation expenses, which were related to costs of serving a growing customer base, as well as increased bad debts, regulatory fees and utility plant investments; and

- an increase in income tax expense of $0.5 million, corresponding with the higher taxable income.

Six months ended June 30, 2006 compared to June 30, 2005:

For the six months ended June 30, 2006, net income increased 5 percent to $43.0 million, or $1.56 a share, compared to $41.0 million, or $1.48 a share, in the same period in 2005. NW Natural s utility operations contributed $39.7 million, or $1.44 a share, to earnings in the first six months of 2006, compared to $38.9 million, or $1.40 a share, in 2005. Interstate gas storage operations contributed $3.3 million in the current period, or 12 cents a share, compared to $1.7 million, or 6 cents a share, in 2005. Other non-utility activities resulted in net income of $0.1 million, or less than 1 cent a share, compared to net income of $0.4 million, or 2 cents a share, in 2005.

Primary factors affecting year-to-date earnings this year over last year include:

- an increase in utility margin from residential and commercial customers of $6.1 million, or 4 percent, primarily resulting from customer growth, colder weather and the impact of our decoupling mechanism, which largely mitigated the negative effects of declining use from customer conservation;

- a decrease in utility margin from industrial customers of $0.3 million, or 2 percent, primarily due to a $0.3 million net loss from a temporary mark-to-market contract adjustment

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- and a higher percentage of volumes in lower margin rate schedules, partially offset by higher delivered volumes;

- an increase in utility margin of $1.6 million from higher gas purchase savings under the regulatory PGA incentive mechanism;

- an increase in interstate gas storage margin of $2.8 million, or 70 percent, reflecting stronger demand for storage services and increased optimization activities;

- an increase in total operating expenses of $4.9 million, or 5 percent, reflecting a combination of higher costs related to customer growth, bad debts, regulatory fees and utility plant investments; and

- an increase in income tax expense of $1.1 million, corresponding with the higher taxable income.

Dividends paid on common stock were 34.5 cents and 32.5 cents a share in the three-month periods ended June 30, 2006 and 2005, respectively, and 69 cents and 65 cents a share in the six-month periods ended June 30, 2006 and 2005, respectively. In July 2006, the Board of Directors declared a dividend of 34.5 cents a share on the common stock, payable Aug. 15, 2006, to shareholders of record on July 31, 2006. The current indicated annual dividend rate is $1.38 a share.

Results of Operations

Regulatory Developments

We provide gas utility service in Oregon and Washington, with Oregon representing over 90 percent of our utility revenues. Future earnings and cash flows from utility operations will be determined by, among other factors, our ability to obtain reasonable and timely regulatory treatment for operating expenses and investments in utility plant. See Part II, Item 7., Results of Operations Regulatory Matters, in the 2005 Form 10-K.

General Rate Cases

On June 30, 2006, the two companies that provide interstate pipeline transportation of our gas supplies filed general rate cases. Williams Gas Pipeline West, or Northwest Pipeline, filed for a 49 percent rate increase, which would increase our rates by approximately $17.4 million annually. The primary drivers for Northwest Pipeline s proposed increase are pipeline integrity expenses, mainline and other extension construction, capacity replacement and displacement of supply from the Rocky Mountain region. Gas Transmission Northwest, or GTN, filed for a rate increase of 71 percent, which would increase our rates by approximately $3.1 million. The primary drivers for GTN s rate increase are return on equity, capital structure, capacity releases and pipeline integrity expenses. Rates for both Northwest Pipeline and GTN are expected to be effective January 1, 2007, subject to credit to customers. Increases in pipeline transportation expenses are subject to our PGA mechanism and are 100 percent passed-through to customers in both Oregon and Washington. See Rate Mechanisms, below.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA mechanisms in our tariffs in Oregon and Washington to reflect changes in the costs of natural gas commodity purchased under contracts with gas producers, the application of temporary rate adjustments to amortize balances in deferred regulatory asset and liability 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 are higher than the amounts included in rates, we are required to defer a predetermined percentage of the higher costs and collect them in future rates. Similarly, when the actual purchased gas costs are lower than the amounts included in rates, the gas

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cost savings are not immediately returned to customers, but a predetermined percentage is deferred and credited to customers in future periods. As part of an incentive mechanism in Oregon, the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

Geo-hazard Program. We entered into a stipulation with the OPUC in 2001 for an enhanced pipeline safety program that included an accelerated bare steel replacement program and a geo-hazard safety program. The geo-hazard safety program included the identification, assessment and remediation of risks to piping infrastructure created by landslides, washouts, earthquakes or similar occurrences. The stipulation allowed NW Natural to receive deferred accounting rate treatment for all costs associated with the geo-hazard program. The authority to defer expenses for costs associated with the geo-hazard program is scheduled to expire on Dec. 31, 2006.

Utility Regulation Legislation

During 2005, the Oregon legislature passed Senate Bill (SB) 408 relating to taxes collected by utilities on or after Jan. 1, 2006. This legislation requires the OPUC to establish an annual tax adjustment to ensure that Oregon utilities do not collect in rates more income taxes than they actually pay to government entities. See Part I, Item 1., Regulation and Rates Utility Regulation Legislation, Part 1A., Risk Factors, and Part II, Item 7., Results of Operations Regulatory Matters Utility Regulation Legislation, in the 2005 Form 10-K. The OPUC continues to develop rules required to implement SB 408 with a proposed set of final rules distributed by the OPUC on July 25, 2006, and adoption of final rules scheduled to take place in September. We continue to participate in the rulemaking development process, along with members of the OPUC s staff, interveners and other affected utilities. However, due to the many uncertainties with respect to the implementation of the OPUC s proposed final rules, we are not able to determine at this time what impact, if any, the new legislation will have on our financial condition, results of operations or cash flows, but the impact may be material.

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Comparison of Gas Distribution Operations

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

Thousands, except degree day and customer data	Three Months Ended June 30, 2006		2005	
Utility volumes - therms:				
Residential and commercial sales	95,097	41%	99,193	41%
Industrial sales and transportation	134,481	59%	140,547	59%
Total utility volumes sold and delivered	229,578	100%	239,740	100%
Utility operating revenues - dollars:				
Residential and commercial sales	$ 127,762	76%	$ 113,807	75%
Industrial sales and transportation	38,086	23%	37,267	25%
Other revenues	1,402	1%	573	0%
Total utility operating revenues	167,250	100%	151,647	100%
Cost of gas sold	105,007		92,378	
Revenue taxes	4,196		3,593	
Utility net operating revenues (margin)	$ 58,047		$ 55,676	
Utility Margin: (1)				
Residential sales	$ 33,556	58%	$ 34,357	62%
Commercial sales	13,699	24%	14,517	26%
Industrial - firm sales and transportation	2,864	5%	3,057	6%
Industrial - interruptible sales and transportation	4,840	8%	4,671	8%
Miscellaneous revenues	1,145	2%	1,331	2%
Other margin adjustments	1,982	3%	405	1%
Margin before weather normalization and decoupling	58,086	100%	58,338	105%
Weather normalization mechanism	844	1%	(691)	-1%
Decoupling mechanism	(883)	-1%	(1,971)	-4%
Utility margin	$ 58,047	100%	$ 55,676	100%
Customers - end of period:				
Residential customers	563,750		544,595	
Commercial customers	59,853		59,027	
Industrial customers	942		950	
Total number of customers - end of period	624,545		604,572	
Actual degree days	572		652	
Percent colder (warmer) than average (2)	(16%)		(5%)	

(25-year average degree days is used as average)

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Thousands, except degree day data	Six Months Ended June 30, 2006		2005	
Utility volumes - therms:				
Residential and commercial sales	349,734	55%	330,405	54%
Industrial sales and transportation	287,780	45%	278,505	46%
Total utility volumes sold and delivered	637,514	100%	608,910	100%
Utility operating revenues - dollars:				
Residential and commercial sales	$ 454,913	82%	$ 372,801	81%
Industrial sales and transportation	99,631	18%	79,806	17%
Other revenues	(38)	0%	5,726	1%
Total utility operating revenues	554,506	100%	458,333	100%
Cost of gas sold	360,391		272,945	
Revenue taxes	13,724		10,776	
Utility net operating revenues (margin)	$ 180,391		$ 174,612	
Utility Margin: [1]				
Residential sales	$ 111,904	62%	$ 104,412	60%
Commercial sales	45,476	25%	42,192	24%
Industrial - firm sales and transportation	6,472	4%	6,798	4%
Industrial - interruptible sales and transportation	9,718	5%	9,729	5%
Miscellaneous revenues	2,648	2%	3,229	2%
Other margin adjustments	3,422	2%	2,870	2%
Margin before weather normalization and decoupling	179,640	100%	169,230	97%
Weather normalization mechanism	2,686	1%	2,555	1%
Decoupling mechanism	(1,935)	-1%	2,827	2%
Utility margin	$ 180,391	100%	$ 174,612	100%
Actual degree days	2,386		2,421	
Percent colder (warmer) than average [2]	(6%)		(5%)	

(25-year average degree days is used as average)

(1) Amounts reported as margin for each category is net of demand charges and revenue taxes. In prior years, customer margin by category did not reflect these costs but have been revised to be consistent with the current year s presentation. We believe the current presentation is a better representation of the margin earned from each class of customer. See Note 1.

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

Our utility results are affected by, among other things, customer growth and changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In order to offset the potential volatility in utility earnings caused by these factors, 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 Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2005 Form 10-K).

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Three months and six months ended June 30, 2006 compared to June 30, 2005:

Total utility volumes sold and delivered in the second quarter this year over last year decreased 4 percent, while total utility margin increased by 4 percent. Total utility volumes sold and delivered in the first half of this year over last year increased 5 percent due mainly to customer growth, which has continued to remain strong, with a net increase of 19,973 customers since June 30, 2005 or an annual growth rate of 3.3 percent.

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 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. However, this mechanism applies to approximately 92 percent of our Oregon customers, but we do not have a weather normalization mechanism in Washington, where about 10 percent of our customers are served. As a result, the mechanism does not fully insulate utility earnings from volatility due to weather. We also utilize a 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.

The weather normalization mechanism recovered a net $0.8 million of margin in the second quarter of 2006 on weather that was 16 percent warmer than average. This compares to a reduction of $0.7 million to margin in the same period last year based on weather that was 5 percent warmer than average. The decoupling mechanism reduced margin by $0.9 million in the second quarter of 2006, compared to a reduction of $2.0 million in the same period last year.

During the six-month period in 2006, the weather normalization mechanism recovered a net $2.7 million of margin based on 6 percent warmer than average weather, compared to a margin recovery of $2.5 million in the same 2005 period based on 5 percent warmer than average weather. The decoupling mechanism reduced margin by $1.9 million in the first six months of 2006, compared to a contribution of $2.8 million in the same period last year.

The following table summarizes the utility volumes and utility operating revenues in the residential and commercial markets:

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	**2006**	**2005**	**2006**	**2005**
Utility volumes - therms:				
Residential sales	72,047	71,569	248,158	230,500
Commercial sales	48,295	47,508	151,611	140,857
Change in unbilled sales	(25,245)	(19,884)	(50,035)	(40,952)
Total weather-sensitive utility volumes	95,097	99,193	349,734	330,405
Utility operating revenues - dollars:				
Residential sales	$ 100,808	$ 86,888	$ 339,191	$ 276,139
Commercial sales	56,863	47,803	178,563	142,226
Change in unbilled sales	(29,909)	(20,884)	(62,841)	(45,564)
Total weather-sensitive utility revenues	$ 127,762	$ 113,807	$ 454,913	$ 372,801

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Three months ended June 30, 2006 compared to June 30, 2005:

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

- sales volumes were 4 percent lower, reflecting the effect of 12 percent warmer weather, partially offset by 3.3 percent customer growth; and

- operating revenues were 12 percent higher due to customer growth and higher billing rates, which reflect the higher gas costs in the PGA effective Oct. 1, 2005 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2005 Form 10-K).

Six months ended June 30, 2006 compared to June 30, 2005:

The primary factors affecting residential and commercial volumes and operating revenues year-to-date this year over last year include:

- sales volumes were 6 percent higher, mainly resulting from customer growth of 3.3 percent and colder weather in the first quarter when there are more heating degree days; and

- operating revenues were 22 percent higher, due to customer growth and higher billing rates, which reflect the higher gas costs in the PGA effective Oct. 1, 2005 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2005 Form 10-K) and colder weather in the first quarter of 2006 compared to a similar period in 2005 when the effect of weather is greater, slightly offset by the smaller incremental effect of warmer weather in the second quarter of 2006 compared to a similar period in 2005.

Total utility operating revenues include accruals for unbilled revenues (gas delivered but not yet billed to customers) based on estimates of gas deliveries from that month s meter reading dates to month end. Amounts reported as unbilled revenues reflect the increase or decrease in the balance of accrued unbilled revenues compared to the prior period end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenues at the end of each month. At June 30, 2006, accrued unbilled revenue was $16.7 million compared to $17.2 million at June 30, 2005.

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Industrial Sales and Transportation

The following table summarizes the delivered volumes and utility operating revenues in the industrial market:

Thousands	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Utility volumes - therms:				
Industrial - firm sales	15,924	16,823	40,075	38,561
Industrial - firm transportation	35,348	37,215	65,091	66,312
Industrial - interruptible sales	25,256	35,130	68,444	71,448
Industrial - interruptible transportation	58,358	51,827	115,313	103,161
Change in unbilled sales	(405)	(448)	(1,143)	(977)
Total utility volumes	134,481	140,547	287,780	278,505
Utility operating revenues - dollars:				
Industrial - firm sales	$ 15,404	$ 13,503	$ 39,156	$ 31,047
Industrial - firm transportation	1,169	1,027	2,117	2,114
Industrial - interruptible sales	20,384	21,376	55,736	43,989
Industrial - interruptible transportation	1,868	1,745	3,727	3,492
Change in unbilled sales	(739)	(384)	(1,105)	(836)
Total utility operating revenues	$ 38,086	$ 37,267	$ 99,631	$ 79,806

Three months ended June 30, 2006 compared to June 30, 2005:

Total volumes delivered to industrial sales and transportation customers were down 6.1 million therms, or 4 percent, in the second quarter of 2006 as compared to the same period in 2005. Utility operating revenues were up $0.8 million, or 2 percent, over last year. The higher revenues reflect higher billing rates due to increased gas costs. However, the margin contribution from industrial sales and transportation was flat compared to 2005, primarily driven by a $0.4 million gain recognized from a temporary mark-to-market contract adjustment, offset by a decrease in volumes and a higher percentage of volumes in lower margin rate schedules.

Six months ended June 30, 2006 compared to June 30, 2005:

Total volumes delivered to industrial sales and transportation customers were up 9.3 million therms, or 3 percent, in the six months ended June 30, 2006, as compared to the same period in 2005. Utility operating revenues were up $19.8 million, or 25 percent, over last year. The higher revenues primarily reflect higher billing rates due to increased gas costs, plus higher volumes delivered. The margin contribution from industrial sales and transportation decreased by $0.3 million, or 2 percent, over 2005, due to a $0.3 million temporary net loss mark-to-market adjustment related to the valuation of a gas sales contract and a higher percentage of volumes in lower margin rate schedules, partially offset by higher delivered volumes.

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 deferrals relating to gas costs (see Part II, Item 8., Note 1, Industry Regulation, in the 2005 Form 10-K). Other revenues increased net operating revenues by $1.4 million in the second quarter of 2006, compared to an increase of $0.6 million in the second quarter of 2005. In the first half of 2006, other revenues were negligible, compared to an increase of $5.7 million in the first half of 2005. The following table summarizes other revenues by major category:

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	**2006**	**2005**	**2006**	**2005**
Current regulatory deferrals:				
Decoupling mechanism	$ (883)	$ (1,971)	$ (1,935)	$ 2,827
Weather normalization mechanism	(1,335)	(505)	234	(33)
South Mist pipeline extension		212		293
Coos Bay distribution system		98		703
Current regulatory amortizations:				
Interstate gas storage credits	4,051	2,714	4,051	2,714
Decoupling mechanism	(1,141)	(397)	(3,829)	(1,236)
South Mist pipeline extension	(15)	(499)	(51)	(1,568)
Coos Bay distribution system	(213)		(693)	
Conservation programs	(304)	(441)	(978)	(1,329)
Other	97	75	324	235
Net revenue adjustments	257	(714)	(2,877)	2,606
Customer fees	1,076	1,251	2,721	3,021
Other	69	36	118	99
Total miscellaneous revenues	1,145	1,287	2,839	3,120
Total other revenues	$ 1,402	$ 573	$ (38)	$ 5,726

Three months ended June 30, 2006 compared to June 30, 2005:

Other revenues in the three months ended June 30, 2006 were $0.8 million higher than in the three months ended June 30, 2005 primarily due to an increase in interstate gas storage credits ($1.3 million), partially offset by an increase in the amortization of the decoupling deferral balances ($0.7 million).

Six months ended June 30, 2006 compared to June 30, 2005:

Other revenues in the six months ended June 30, 2006 were $5.7 million lower than in the six months ended June 30, 2005 primarily due to a decrease in decoupling deferrals ($4.8 million) and an increase in amortization of decoupling deferral balance ($2.6 million), partially offset by an increase in interstate gas storage credits ($1.3 million). For further discussion of regulatory revenue adjustments, see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2005 Form 10-K.

Cost of Gas Sold

Although natural gas commodity prices have increased significantly in the last few years, prices had moderated recently, allowing more opportunity to purchase lower-priced spot market gas. During the second quarter and the first six months of 2006, the cost per therm of gas sold was 27 percent and 16 percent higher, respectively, than in the comparable 2005 periods, reflecting higher natural gas prices and our fixed-price commodity price hedge contracts. The cost per therm of gas sold includes current gas purchases, gas withdrawn from storage inventory, gains and losses from financial commodity hedges, margin from off-system gas sales, demand cost balancing adjustments, regulatory deferrals and company use.

We use a natural gas commodity-price hedge program under the terms of our Derivatives Policy to help manage our variable price risk on gas purchases. We realized a net loss from financial hedge contracts of $10.5 million in the three months ended June 30, 2006 compared to a gain of $11.3 million during the same period in 2005. During the six months ended June 30, 2006, we realized a net hedge gain of $7.0 million compared a gain of $9.8 million during the same period in 2005. Gains and losses relating to the financial hedging of utility gas purchases are included in cost of gas. Realized losses were factored into our PGA deferrals and annual rate changes. As such, these gains and losses have no material impact on net income.

Under our PGA tariff in Oregon, if the cost of gas purchased is higher or lower than the cost embedded in rates, net income is charged or credited for 33 percent of the difference and the remaining 67 percent is deferred for pass through to customers in future rates. Our gas purchases in the second quarter of 2006 were lower than the costs embedded in rates, and our share of the lower costs increased margin by $1.8 million. For the second quarter of 2005, our gas costs were also lower than the gas costs embedded in rates, and our share of the lower costs increased margin by $0.2 million. In the first six months of 2006, our share of gas cost savings contributed $3.6 million to margin, compared to net savings and a contribution to margin of $2.0 million in the comparable 2005 period. The benefit to customers of gas cost savings amounted to $3.7 million and $7.4 million for the three and six months ended June 30, 2006, respectively.

Based on current forward curve prices, we began moderating our hedging positions compared to prior years, but at the same time we have increased our gas inventory injections into storage while spot prices were lower. Typically, we have a higher percentage of the next gas year s estimated purchase requirements hedged at this time of year. We may or may not increase our hedging positions to be closer to the level of the past few years, depending on movement in forward market prices and our assessment of risk. Having a greater percentage of unhedged gas purchases may subject NW Natural to greater purchased gas cost variability in the future as compared to previous years. See Part II, Item 1A., Risk Factors, below. Variations in gas costs are subject to our PGA mechanism. See Results of Operations Rate Mechanisms, above.

Business Segments Other than Gas Distribution Operations

Interstate Gas Storage

Net income from our non-utility interstate gas storage business segment in the three and six months ended June 30, 2006 was $1.8 million and $3.3 million, respectively, after regulatory sharing and income taxes, or 6 cents and 12 cents a share, respectively. This compares to net income of $0.8 million, or 3 cents a share, and $1.7 million, or 6 cents a share, in the three and six months ended June 30, 2005, respectively. The increase was primarily due to additional interstate storage capacity brought on line during mid-year 2005 and an increase in revenues from our asset optimization program with an unaffiliated energy marketing company (see Part II, Item 7., Results of Operations Business Segments Other Than Local Gas Distribution Interstate Gas Storage, in the 2005 Form 10-K). The segment also began providing intrastate services in February 2006.

Third-party optimization services are provided pursuant to a contract with an unaffiliated energy marketing company, which assists in the optimization of the value of our 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

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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 assistance.

Other

The Other business segment primarily consists of a wholly-owned subsidiary, Financial Corporation (see Part II, Item 8., Note 2, Consolidated Subsidiary Operations and Segment Information, in the 2005 Form 10-K). Financial Corporation s operating results for the three months ended June 30, 2006 were net income of $0.1 million compared to $0.2 million in the second quarter of 2005. For the first six months of both 2006 and 2005, results were net earnings of $0.1 million. In addition, the Other segment includes various other investments, including an investment in a leveraged aircraft lease.

Our net investment balances in Financial Corporation at June 30, 2006 and 2005 were $3.5 and $3.1 million, respectively. The $0.4 million increase primarily reflects higher temporary cash investments, partially offset by a decline in the carrying value of long-term investments. Our net investment balance in the leveraged aircraft lease at June 30, 2006 and 2005 was $7.1 million and $6.8 million, respectively. The $0.3 million increase is due to recognition of earned lease revenue.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the second quarter of 2006 were $27.9 million, representing a $0.9 million, or 3 percent, increase over the second quarter of 2005. In addition to the costs of serving a 3.3 percent larger customer base, the following contributed to the increase in operations and maintenance expense:

- a $0.5 million increase in uncollectible accounts expense primarily related to increases in gross revenues and delinquencies resulting from higher natural gas prices;
- a $0.4 million increase for corporate development expenses;
- offset, in part, by a $0.3 million decrease in injury and damage claims.

Operations and maintenance expenses in the first six months of 2006 were an increase of $2.0 million, 4 percent higher than in the first six months of 2005. The following summarizes the major factors that contributed to the increase in operations and maintenance expense:

- a $1.2 million increase in payroll-related expenses resulting from pay increases and higher benefit costs;
- a $0.9 million increase in uncollectible accounts expense related to increases in gross revenues and delinquencies resulting from higher natural gas prices;
- a $0.4 million increase for corporate development expenses;
- a $0.4 million increase in stock option expense due to the required adoption of a new accounting rule related to share-based compensation (see Notes 2 and 4);

offset, in part, by a $0.7 million decrease in injury and damage claims.

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, increased $0.9 million, or 16 percent, and $1.7 million, or 14 percent, in the three- and six- month periods ended June 30, 2006, respectively, over the same periods in 2005. Property taxes increased $0.3 million, or 8 percent, and $0.6 million, or 8 percent, in the three- and six- month periods

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ended June 30, 2006, respectively, over the same periods in 2005, due to utility plant additions in 2006 and 2005. Regulatory fees increased $0.5 million and $0.9 million in the three- and six-month periods ended June 30, 2006, respectively, over the same periods in 2005, reflecting increased gross operating revenues and the timing impact of payments made in the second quarter of 2006.

Depreciation and Amortization

Depreciation and amortization expense increased by $0.6 million, or 4 percent, and $1.3 million, or 4 percent, in the three- and six-month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The increased expense reflects ongoing capital expenditures in utility plant that were made primarily to meet continuing customer growth and upgrade operating facilities.

Other Income and Expense Net

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

	Three months ended June 30,		Six months ended June 30,	
Thousands	**2006**	**2005**	**2006**	**2005**
Other income (expense):				
Gains from Company-owned life insurance	$ 414	$ 505	$ 1,797	$ 973
Interest income	191	183	275	229
Other non-operating expense	(215)	(497)	(818)	(810)
Interest charges on deferred regulatory account balances	(89)	23	(385)	24
Earnings from equity investments of Financial Corporation	109	191	59	54
Total other income	$ 410	$ 405	$ 928	$ 470

Other income and expense net was unchanged in the second quarter of 2006 compared to 2005, and $0.5 million higher in the six months ended June 30, 2006 compared to the six months ended June 30, 2005. The increase in the six-month period was due to realized gains in the first quarter from company-owned life insurance, partially offset by higher non-operating expense and higher interest charges on deferred regulatory accounts.

Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized increased $0.3 million, or 3 percent, and $1.0 million, or 6 percent, in the three- and six-month periods ended June 30, 2006 and 2005, respectively, due to higher balances of total debt outstanding.

Income Taxes

The effective corporate income tax rate from operations was 36.3 percent for each of the six-month periods ended June 30, 2006 and 2005.

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

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paper maturities (see Liquidity and Capital Resources, below). Our consolidated capital structure at June 30, 2006 and 2005 and at Dec. 31, 2005, including short-term debt, was as follows:

	June 30,		Dec. 31,
	2006	2005	2005
Common stock equity	51.4%	51.9%	47.2%
Long-term debt	41.4%	45.7%	42.0%
Short-term debt, including current maturities of long-term debt	7.2%	2.4%	10.8%
Total	100.0%	100.0%	100.0%

The increase in common stock equity percentage in June of 2006 compared to December of 2005 is primarily related to a reduction of short-term debt of $70.9 million, combined with an increase in common stock equity at June 30, 2006 of $24.0 million. 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.

The Board has approved a program for the repurchase of up to 2.6 million shares, or up to $85 million in value, of our common stock. Purchases under this program are made in the open market or through privately negotiated transactions. Since the program s inception in 2000, we have repurchased 812,700 shares of common stock at a total cost of $24.7 million, including 47,100 shares at a total cost of $1.6 million in the first six months of 2006. (see Financing Activities, below).

Liquidity and Capital Resources

At June 30, 2006, we had $6.6 million of cash and cash equivalents compared to $40.3 million at June 30, 2005. The higher balance at June 30, 2005 reflects the temporary investment of a portion of the proceeds from a sale of $50 million of medium-term-notes in the second quarter of 2005. At Dec. 31, 2005, the balance in cash and cash equivalents was $7.1 million, which was comparable to the balance at June 30, 2006. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed bank lines of credit totaling $200 million and available through Sept. 30, 2010 (see Lines of Credit, below, and Part II, Item 8., Note 6, in the 2005 Form 10-K). Proceeds from the issuance of long-term debt are used to finance capital expenditures, refinance maturing short-term or long-term debt, and manage the capital structure.

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

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

Off-Balance Sheet Arrangements

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

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Contractual Obligations

Since Dec. 31, 2005, we entered into a new contract in the amount of $12.4 million for the purchase and installation of automated meter reading equipment. Besides this contract and other contracts entered into in the ordinary course of business, there were no material changes to our estimated future contractual obligations during the six months ended June 30, 2006. Our contractual obligations at Dec. 31, 2005 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2005 Form 10-K.

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes payable. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas purchases and accounts receivable, short-term debt is used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by committed bank lines of credit (see Lines of Credit, below, and Part II, Item 8., Note 6, in the 2005 Form 10-K). We had $55.8 million in commercial paper notes outstanding at June 30, 2006, compared to no commercial paper outstanding at June 30, 2005 and $126.7 million outstanding at Dec. 31, 2005. Commercial paper balances are typically lower at the end of the first and second quarters compared to year-end resulting from decreases in customer receivables and gas inventories due to seasonality.

Lines of Credit

We have agreements for unsecured lines of credit totaling $200 million with five commercial banks. The bank lines of credit (bank lines) are available and committed for a term of five years, from Oct. 1, 2005 to Sept. 30, 2010. There were no outstanding balances on these lines of credit at June 30, 2006 or 2005, or at Dec. 31, 2005.

The lines of credit require us to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and to accelerate the maturity of any amounts outstanding. The Company was in compliance with this covenant at June 30, 2006 and at Dec. 31, 2005, and with the equivalent covenant in the prior year s lines of credit at June 30, 2005.

Credit Ratings

The table below summarizes our credit ratings from three rating agencies, Standard and Poor s Rating Services (S&P), Moody s Investors Service (Moody s) and Fitch Ratings (Fitch).

	S&P	Moody s	Fitch
Commercial paper (short-term debt)	A-1+	P-1	F1
Senior secured (long-term debt)	AA-	A2	A+
Senior unsecured (long-term debt)	A+	A3	A
Ratings outlook	Stable	Stable	Stable

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

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Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, gas prices, deferred income taxes and other changes in working capital requirements, regulatory deferrals and other cash and non-cash adjustments to operating results. The overall change in cash flow from operating activities for the six months ended June 30, 2006 compared to the same period in 2005 was a decrease of $13.0 million, primarily due to a net decrease in cash from working capital of $20.9 million. The significant factors contributing to the cash flow changes in the first half of 2006 compared to first half of 2005 are as follows:

- an increase in net income added $2.0 million to cash flow;
- an increase in gas inventories reduced cash flow by $20.7 million, primarily reflecting an increase in gas injection into storage, compared to a decline during 2005;
- an increase in regulatory receivables for deferred gas costs decreased cash flow by $3.2 million, reflecting different patterns of activity between the two years with respect to purchased gas costs embedded in inventory plus gas cost savings and off-system gas sales under NW Natural s PGA tariff (see Results of Operations Comparison of Gas Operations Cost of Gas Sold, above);
- an increase in accounts receivable and accrued unbilled revenue net increased cash flow by $33.1 million due to a collection of higher year-end balances, reflecting higher rates and colder weather;
- a decrease in accounts payable reduced cash flow by $22.5 million due to the payment of higher year-end balances, primarily reflecting higher gas prices;
- an increase in deferred environmental costs expended reduced cash flow by $2.8 million;
- a decrease in other assets, primarily due to an increase in regulatory liabilities, increased cash flow by $8.7 million;
- a decrease in income taxes receivable decreased cash flow by $2.7 million; and
- an increase in prepayments and other current assets reduced cash flow by $5.0 million.

We have lease and purchase commitments relating to operating activities that are financed with cash flows from operations (see Liquidity and Capital Resources, above, and Part II, Item 8., Note 12, in the 2005 Form 10-K).

Investing Activities

Cash requirements for investing activities in the first half of 2006 totaled $33.9 million, down from $38.6 million in the same period of 2005. Cash requirements for the acquisition and construction of utility plant totaled $39.0 million, down from $41.4 million in the first half of 2005 due in part to a reductions in public works projects and purchases of general equipment.

Investments in non-utility property during the first half of 2006 totaled $0.2 million, down from $0.9 million during the first half of 2005 due primarily to including amounts related to the start of improvements to the Company s interstate gas storage facilities in 2005, which were not repeated in 2006.

In January 2005, Financial Corporation received proceeds from the sale of its limited partnership interests in three solar electric generation projects totaling $3.0 million.

Financing Activities

Cash used in financing activities in the first half of 2006 totaled $98.0 million, up from $70.6 million in the same period of 2005. The primary factor contributing to the $27.4 million increase

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results from differences in short-term and long-term debt financings, which consisted of $78.9 million of short-term and long-term debt redemption in 2006, compared to $102.5 million of short-term debt redeemed, partially offset by $50 million of long-term debt proceeds in 2005.

Under our common stock repurchase program we purchased 47,100 shares at a cost of $1.6 million in the first half of 2006, compared to 134,800 shares at a cost of $4.9 million in the first half of 2005.

Ratios of Earnings to Fixed Charges

For the six months and 12 months ended June 30, 2006 and the 12 months ended Dec. 31, 2005, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 4.47, 3.37 and 3.32, 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.

Contingencies

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. We update our estimates of loss contingencies and related disclosures when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties, and we record accruals for loss contingencies 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 lower end of the range and disclose the range (see Note 9). It is possible, however, that the range of potential liabilities could be significantly different than amounts currently accrued and disclosed, and our financial condition and results of operations could be materially affected by changes in assumptions or estimates related to theses contingencies.

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 (see Results of Operations Regulatory Developments Rate Mechanisms, above). 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. At June 30, 2006, a cumulative $21.7 million in environmental costs has been recorded as a regulatory asset, including $16.0 million of costs paid to-date and $5.7 million of accrued estimated future environmental expenditures. If it is determined that both the insurance recovery and future customer rate recovery of such costs is not probable, then the costs will be charged to expense in the period such determination is made. See Note 9.

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. 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

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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 Washington Utilities and Transportation Commission (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, and regulations, policies, orders and laws with respect to the maintenance of pipeline integrity;
- adoption and implementation by the OPUC of rules interpreting recent Oregon legislation intended to ensure that utilities do not collect in rates more income taxes than they actually pay to government entities;
- weather conditions and other natural phenomena, including earthquakes or other geo-hazard events;
- unanticipated population growth or decline, and changes in market demand caused by changes in demographic or customer consumption patterns;
- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- risks relating to the creditworthiness of customers, suppliers and derivative counterparties;
- risks relating to dependence on a single pipeline transportation provider for natural gas supply;
- risks relating to property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- unanticipated changes that may affect our liquidity or access to capital markets;
- our ability to maintain effective internal controls over financial reporting;
- 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;

our ability to achieve the cost savings expected from operational design changes;

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 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 supply risk, weather risk, and interest rate risk. For further information regarding these risks see Item 7A. in the 2005 Form 10-K and below. Also see Note 6, above, and Part II, Item 1A., Risk Factors, below.

Commodity Supply Risk

We enter into short-term, medium-term and long-term natural gas supply contracts, along with associated short-, medium- and long-term transportation capacity contracts. Historically, we have taken physical delivery of at least the minimum quantities specified in our natural gas supply contracts. These contracts are primarily index-based and subject to annual re-pricing, a process that is intended to reflect anticipated market price trends during the next year. Our PGA mechanisms in Oregon and Washington provide for the recovery from customers of actual commodity costs, except that, for Oregon customers, we absorb 33 percent of the higher cost of gas sold, or retain 33 percent of the lower cost, in either case as compared to the annual PGA price built into customer rates.

Based on current forward curve prices, we began moderating our hedging positions compared to prior years, but at the same time we have increased our gas inventory injections into storage while spot prices were lower. Typically, we have a higher percentage of the next gas year s estimated purchase requirements hedged at this time of year. We may or may not increase our hedging positions to be closer to the level of the past few years, depending on movement in forward market prices and our assessment of risk. Having a greater percentage of unhedged gas purchases may subject NW Natural to greater purchased gas cost variability in the future as compared to previous years. See Part II, Item 1A., Risk Factors, below. Variations in gas costs are subject to our PGA mechanism. See Part I, Item 2., Results of Operations Rate Mechanisms, above.

Credit Risk

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity swap contracts was $1.9 million at June 30, 2006. Our Derivatives Policy requires counterparties to have a minimum investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty s credit rating. There were no credit rating downgrades for any of our counterparties during the quarter.

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

	Financial Derivative Exposure by Credit Rating Unrealized Fair Value Gain		
	June 30,		Dec. 31,
Thousands	**2006**	**2005**	**2005**
AA/Aa	$ 1,853	$ 61,360	$ 172,315
BBB/Baa		1,104	3,346
Total	$ 1,853	$ 62,464	$ 175,661

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Credit exposure to customers. Increases in the market price of natural gas are expected to increase our credit exposure to customers. Also, higher gas prices have resulted in some of our largest industrial customers switching from transportation service to sales service. Under transportation service, the customer is purchasing its commodity supplies from an independent third party, while we only provide the transportation service for delivery of that gas to the customer s premise. Under sales service, the customer is purchasing both its gas commodity supply and transportation service from us. With higher natural gas commodity prices, our credit exposure to large industrial sales customers has increased. We monitor and manage the credit exposure of our industrial sales customers through credit policies and procedures, which are designed to reduce credit risk. These policies and procedures include an ongoing review of credit risks, including changes in the services provided to industrial customers as well as changes in market conditions and customers credit quality. Changes in credit risk may require us to obtain additional assurance, such as deposits, letters of credit, guarantees or prepayments to reduce our credit exposure.

We also monitor and manage the credit exposure of our residential and commercial customers. This credit risk is largely mitigated by the nature of our regulated business and reasonably short collection terms, as well as by the consistent application of credit policies and procedures.

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures
As of June 30, 2006, the principal executive officer and principal financial officer of NW Natural have evaluated the effectiveness of the design and operation of NW Natural s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act)). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by NW Natural and included in NW Natural s reports filed with or furnished to the Securities and Exchange Commission under the Exchange Act is accumulated and communicated to NW Natural s management as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting
There has been no change in NW Natural s internal control over financial reporting that occurred during NW Natural s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, NW Natural s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

For a discussion of certain pending legal proceedings, see Note 9, 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, 2005, which could materially affect our business, financial condition or results of operations. The risks described in our Annual Report on 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 business, financial condition or results of operations.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table provides information about purchases by us during the quarter ended June 30, 2006 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			777,300	$ 61,472,462
04/01/06- 04/30/06	1,434	$ 34.35	3,900	(137,301)
05/01/06- 05/31/06	26,234	$ 34.35	31,500	(1,074,464)
06/01/06- 06/30/06	5,120	$ 35.13		
Total	32,788	$ 34.47	812,700	$ 60,260,697

(1) During the quarter ended June 30, 2006, 31,841 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan (DSPP). Prior to December 2005, the requirements of the DSPP were met by issuing original issue shares of common stock. In addition, 947 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended June 30, 2006, 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. Since the program s inception, we have repurchased 812,700

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shares of common stock at a total cost of $24.7 million. In April 2006, NW Natural s Board of Directors extended the program through May 31, 2007 and increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million.

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

NW Natural s Annual Meeting of Shareholders was held in Portland, Oregon on May 25, 2006. At the meeting, four director-nominees were elected, as follows:

Director	Class	Term Expiring	Votes For	Votes Withheld
Timothy P. Boyle	I	2009	23,353,372	345,871
Mark S. Dodson	I	2009	23,249,758	449,485
Randall C. Papé	I	2009	17,658,362	6,040,881
Richard L. Woolworth	I	2009	23,354,765	344,478

The other seven directors whose terms of office as directors continued after the Annual Meeting are: Martha L. (Stormy) Byorum, John D. Carter, C. Scott Gibson, Tod R. Hamachek, Richard G. Reiten, Kenneth Thrasher and Russell F. Tromley.

The following matters also were acted upon at the meeting:

The Company s Long-Term Incentive Plan was reapproved by the following vote:

FOR	AGAINST	ABSTAIN
22,472,902	859,712	366,626

Amendments to the Company s Employee Stock Purchase Plan were approved by the following vote:

FOR	AGAINST	ABSTAIN	BROKER NON-VOTES
16,846,839	709,245	356,490	5,786,668

The restatement of the Company s Restated Articles of Incorporation was approved by the following vote:

FOR	AGAINST	ABSTAIN
22,976,698	295,753	426,790

The amendment of Article IV of the Company s Restated Articles of Incorporation was approved by the following vote:

FOR	AGAINST	ABSTAIN
22,993,767	296,213	409,260

The ratification of the Audit Committee s appointment of PricewaterhouseCoopers LLP as the Company s independent public accountants for the year 2006 was approved by the following vote:

FOR	AGAINST	ABSTAIN

23,225,158	282,091	191,992

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There were no broker non-votes except on the proposal to amend the Employee Stock Purchase Plan, as shown above.

No other matters were acted upon at the meeting.

Item 5. OTHER INFORMATION

In addition to the arrangements described in our Proxy Statement relating to the 2006 Annual Meeting of Shareholders, since the commencement of his employment in 2004, David H. Anderson, Senior Vice President and Chief Financial Officer, has been entitled to a severance benefit equal to one-times annual salary if his employment is terminated by NW Natural without cause prior to Sept. 30, 2007.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)

Dated: August 3, 2006

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

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

June 30, 2006

Document	Exhibit Number
Statement re: Computation of Per Share Earnings	11
Computation of Ratio of Earnings to Fixed Charges	12
Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.1
Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.2
Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1