

NORTHWEST NATURAL GAS CO

Form 10-Q

May 04, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2012

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
(State or other jurisdiction of
incorporation or organization)

93-0256722
(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
No

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Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

Large accelerated filer Accelerated filer
Non-accelerated filer Smaller reporting company
(Do not check if a smaller reporting company)

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

At April 30, 2012, 26,800,474 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended March 31, 2012

PART I. FINANCIAL INFORMATION

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Forward-Looking Statements

This report contains “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as “anticipates,” “intends,” “plans,” “seeks,” “believes,” “estimates,” “expects” and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans;
- objectives;
- goals;
- strategies;
- assumptions and estimates;
- future events or performance;
 - trends;
 - cyclicalities;
- earnings and dividends;
 - growth;
 - customer rates;
 - commodity costs;
- operational performance and costs;
- liquidity and financial positions;
- project development and expansion;
 - competition;
 - storage levels and values;
- procurement, development and production levels of gas supplies and reserves;
 - estimated expenditures and investments;
 - costs of compliance;
 - credit exposures;
 - potential efficiencies;
 - impacts of laws, rules and regulations;
 - tax liabilities or refunds;
- outcomes and effects of litigation, regulatory actions, and other administrative matters;
 - projected status and obligations under retirement plans;
 - adequacy of, and shift in mix of, gas supplies;
 - approval and adequacy of regulatory deferrals; and
- environmental, regulatory, litigation and insurance costs and recoveries.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks, and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2011 Annual Report on Form 10-K, Part I, Item 1A. “Risk Factors” and Part II, Item 7. and Item 7A., “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures about Market Risk,” and in Part I, Items 2 and 3, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk,” and Part II, Item 1A, “Risk Factors,” herein.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

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PART I. FINANCIAL INFORMATIONConsolidated Statements of Comprehensive Income
(Unaudited)

Thousands, except per share amounts	Three Months Ended March 31,	
	2012	2011
Operating revenues:		
Gross operating revenues	\$317,494	\$323,088
Less: Cost of sales	169,771	180,625
Revenue taxes	7,855	7,955
Net operating revenues	139,868	134,508
Operating expenses:		
Operations and maintenance	34,416	31,172
General taxes	8,836	8,165
Depreciation and amortization	17,950	17,309
Total operating expenses	61,202	56,646
Income from operations	78,666	77,862
Other income and expense - net	1,005	1,214
Interest expense - net	11,191	10,449
Income before income taxes	68,480	68,627
Income tax expense	27,873	27,854
Net income	40,607	40,773
Other comprehensive income:		
Amortization of non-qualified employee benefit plan liability, net of taxes of \$108 for 2012 and \$96 for 2011	166	146
Comprehensive income	\$40,773	\$40,919
Average common shares outstanding:		
Basic	26,781	26,670
Diluted	26,862	26,724
Earnings per share of common stock:		
Basic	\$1.52	\$1.53
Diluted	\$1.51	\$1.53
Dividends declared per share of common stock	\$0.445	\$0.435

See Notes to Consolidated Financial Statements.

Table of ContentsConsolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Assets:			
Current assets:			
Cash and cash equivalents	\$4,031	\$3,480	\$5,833
Restricted cash	-	924	-
Accounts receivable	90,817	94,521	77,449
Accrued unbilled revenue	44,444	42,342	61,925
Allowance for uncollectible accounts	(3,694)	(3,821)	(2,895)
Regulatory assets	90,490	48,195	94,673
Derivative instruments	1,824	4,861	2,853
Inventories	61,436	53,266	74,363
Gas reserves	6,732	-	4,463
Income taxes receivable	1,735	23,645	7,045
Other current assets	13,075	13,292	22,980
Total current assets	310,890	280,705	348,689
Non-current assets:			
Property, plant and equipment	2,680,537	2,593,553	2,661,102
Less: Accumulated depreciation	779,683	733,639	767,226
Total property, plant and equipment - net	1,900,854	1,859,914	1,893,876
Gas reserves	61,106	-	47,451
Regulatory assets	368,521	345,452	371,392
Derivative instruments	52	1,560	-
Other investments	67,648	69,501	68,263
Restricted cash	4,000	-	4,000
Other non-current assets	14,191	14,421	12,903
Total non-current assets	2,416,372	2,290,848	2,397,885
Total assets	\$2,727,262	\$2,571,553	\$2,746,574

See Notes to Consolidated Financial Statements.

Table of ContentsConsolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,798, 26,673, and 26,756 at March 31, 2012 and 2011 and December 31, 2011, respectively	\$351,005	\$343,787	\$348,383
Retained earnings	402,599	385,899	373,905
Accumulated other comprehensive income (loss)	(7,633)	(6,458)	(7,800)
Total common stock equity	745,971	723,228	714,488
Long-term debt	641,700	551,700	641,700
Total capitalization	1,387,671	1,274,928	1,356,188
Current liabilities:			
Short-term debt	113,700	186,435	141,600
Current maturities of long-term debt	-	50,000	40,000
Accounts payable	60,165	71,839	86,300
Taxes accrued	10,509	10,063	10,747
Interest accrued	10,648	11,470	5,857
Regulatory liabilities	50,341	29,016	31,046
Derivative instruments	53,697	25,655	57,317
Other current liabilities	41,503	38,433	41,597
Total current liabilities	340,563	422,911	414,464
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	438,486	396,357	413,209
Regulatory liabilities	288,131	263,876	278,382
Pension and other postretirement benefit liabilities	189,003	132,053	201,530
Derivative instruments	3,947	13,914	6,536
Other non-current liabilities	79,461	67,514	76,265
Total deferred credits and other non-current liabilities	999,028	873,714	975,922
Commitments and contingencies (see Note 13)			
Total capitalization and liabilities	\$2,727,262	\$2,571,553	\$2,746,574

See Notes to Consolidated Financial Statements.

Table of ContentsConsolidated Statements of Cash Flows
(Unaudited)

Thousands	Three Months Ended March 31,	
	2012	2011
Operating activities:		
Net income	\$40,607	\$40,773
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	17,950	17,309
Deferred tax liabilities	27,089	25,048
Undistributed losses from equity investments	1	25
Non-cash expenses related to qualified defined benefit pension plans	2,007	1,817
Contributions to qualified defined benefit pension plans	(13,800)	(13,645)
Deferred environmental expenditures, net of recoveries	(827)	(1,759)
Other	475	(443)
Changes in assets and liabilities:		
Receivables	6,378	(3,122)
Inventories	12,927	27,119
Taxes accrued	5,072	16,905
Accounts payable	(26,050)	(14,406)
Interest accrued	4,791	6,288
Deferred gas costs	23,663	196
Other - net	13,771	5,959
Cash provided by operating activities	114,054	108,064
Investing activities:		
Capital expenditures	(20,447)	(25,403)
Utility gas reserves	(17,220)	-
Other	(68)	(121)
Cash used in investing activities	(37,735)	(25,524)
Financing activities:		
Common stock issued - net	1,458	(244)
Long-term debt retired	(40,000)	-
Change in short-term debt	(27,900)	(71,000)
Cash dividend payments on common stock	(11,913)	(11,601)
Other	234	328
Cash used in financing activities	(78,121)	(82,517)
Increase (decrease) in cash and cash equivalents	(1,802)	23
Cash and cash equivalents - beginning of period	5,833	3,457
Cash and cash equivalents - end of period	\$4,031	\$3,480
Supplemental disclosure of cash flow information:		
Interest paid	\$6,148	\$4,162
Income taxes paid	\$101	\$-

See Notes to Consolidated Financial Statements.

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Notes to Consolidated Financial Statements
(Unaudited)

1. Organization and Principles of Consolidation

The accompanying consolidated financial statements represent the consolidation of Northwest Natural Gas Company (NW Natural or Company) and all companies that we directly or indirectly control, either through majority ownership or otherwise. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch) and NNG Financial Corporation (NNG Financial). Investments in corporate joint ventures and partnerships that we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method or the cost method, which includes NWN Energy's investment in Palomar Gas Holdings, LLC (PGH). NW Natural and its affiliated companies are collectively referred to herein as "NW Natural." The consolidated financial statements are presented after elimination of all significant intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business and other non-utility investments and business activities.

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments that management considers necessary for a fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2011 Annual Report on Form 10-K (2011 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.

2. Significant Accounting Policies Update

Our significant accounting policies are described in Note 2 of the 2011 Form 10-K. There were no material changes to those accounting policies during the three months ended March 31, 2012. The following are current updates to certain critical accounting policy estimates and subsequent events of the Company, and to accounting standards in general.

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Regulatory Accounting

In applying regulatory accounting principles in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), we capitalize or defer certain costs and revenues as regulatory assets and liabilities. At March 31, 2012 and 2011 and at December 31, 2011, the amounts deferred as regulatory assets and liabilities were as follows:

Thousands	Regulatory Assets		
	March 31, 2012	March 31, 2011	December 31, 2011
Current:			
Unrealized loss on derivatives(1)	\$53,697	\$25,655	\$57,317
Pension and other postretirement benefit liabilities(2)	15,491	10,988	15,491
Other(3)	21,302	11,552	21,865
Total current	\$90,490	\$48,195	\$94,673
Non-current:			
Unrealized loss on derivatives(1)	\$3,947	\$13,914	\$6,536
Income tax asset	63,452	70,241	65,264
Pension and other postretirement benefit liabilities(2)	166,639	115,490	170,512
Environmental costs(4)	112,297	117,544	105,670
Other(3)	22,186	28,263	23,410
Total non-current	\$368,521	\$345,452	\$371,392

Thousands	Regulatory Liabilities		
	March 31, 2012	March 31, 2011	December 31, 2011
Current:			
Gas costs	\$35,584	\$14,144	\$17,994
Unrealized gain on derivatives(1)	1,824	4,861	2,853
Other(3)	12,933	10,011	10,199
Total current	\$50,341	\$29,016	\$31,046
Non-current:			
Gas costs	\$14,462	\$3,932	\$8,420
Unrealized gain on derivatives(1)	52	1,560	-
Accrued asset removal costs	270,837	256,203	267,355
Other(3)	2,780	2,181	2,607
Total non-current	\$288,131	\$263,876	\$278,382

- (1) Unrealized gain and loss on derivatives does not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment mechanism when realized at settlement.
- (2) Certain pension and other postretirement benefit liabilities of the utility are approved for regulatory deferral, including amounts recorded to the pension cost balancing account to mitigate the effects of higher and lower pension expenses. Such deferred amounts earn a rate of return or carrying charge (see Note 8).
- (3)

Other primarily consists of deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

- (4) Environmental costs are related to those sites that are approved for regulatory deferral. In Oregon, we earn a rate of return on amounts paid, whereas amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended. Environmental costs related to Washington were deferred beginning in 2011, with cost recovery and carrying charge to be determined in a future proceeding.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Subsequent Events

There are no subsequent events to report for the period ended March 31, 2012.

New Accounting Standards Update

Adopted Standards

Comprehensive Income. In June 2011, the FASB issued authoritative guidance on the presentation of comprehensive income within the financial statements. An entity can elect to present items of net income and other comprehensive income in one continuous statement—referred to as the statement of comprehensive income—or in two separate, but consecutive, statements. These changes were effective for periods beginning after December 15, 2011. We elected to present net income and other comprehensive income in one continuous statement, “Consolidated Statements of Comprehensive Income.”

Multiemployer Pension Plans. In September 2011, the FASB issued authoritative guidance regarding multiemployer pension plan disclosures. The revised standard is intended to provide more information about an employer’s financial obligations to a multiemployer pension plan and, therefore, help financial statement users better understand the financial health of all significant plans in which the employer participates. The updated guidance was effective for periods beginning after December 15, 2011, and we elected to early adopt the guidance in our 2011 Form 10-K. Please see Note 9 in our 2011 Form 10-K for more detail.

Fair Value Measurement. In May 2011, the FASB issued amendments to the authoritative guidance on fair value measurement. The amendments are primarily related to disclosure requirements for Level 3 fair value assets and were effective for periods beginning after December 15, 2011. The adoption of this standard did not have a material effect on our financial statement disclosures.

Recent Accounting Pronouncements

Balance Sheet Offsetting. In December 2011, the FASB issued authoritative guidance regarding the offsetting of assets and liabilities on the balance sheet. The revised standard is intended to provide more comparable guidance between the U.S. GAAP and international accounting standards by requiring entities to disclose both gross and net amounts for assets and liabilities offset on the balance sheet as well as other disclosures concerning their enforceable master netting arrangements. This guidance is effective for annual reporting periods beginning after January 1, 2013, and we are currently assessing the impact on our financial statement disclosures.

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3. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed using the weighted average number of common shares outstanding plus the potential effects of the assumed exercise of stock options, and payment of estimated stock awards from other stock-based compensation plans that are outstanding, at the end of each period presented. Diluted earnings per share are calculated as follows:

Thousands, except per share amounts	Three Months Ended March 31,	
	2012	2011
Net income	\$40,607	\$40,773
Average common shares outstanding - basic	26,781	26,670
Additional shares for stock-based compensation plans(1)	81	54
Average common shares outstanding - diluted	26,862	26,724
Earnings per share of common stock - basic	\$1.52	\$1.53
Earnings per share of common stock - diluted	\$1.51	\$1.53
(1)Additional shares not included in diluted earnings per share calculation because of antidilutive impact	1,010	2,150

4. Segment Information

We operate in two primary reportable business segments, which we refer to as “utility” and “gas storage.” We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as “other.” We also refer to our gas storage and other business segments as “non-utility.” Our gas storage segment includes: NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy; Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage; the non-utility portion of our underground storage facility in Oregon (Mist); and revenues from third-party asset management services. Our other segment includes NNG Financial and our equity investment in PGH, which is pursuing development of the Palomar pipeline project. For the periods presented, intersegment transactions were insignificant. For further discussion of our segments, see Note 4 in our 2011 Form 10-K.

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The following table presents summary financial information about the reportable segments for the three months ended March 31, 2012 and 2011:

Thousands	Three Months Ended March 31, Non-Utility			Total
	Utility	Gas Storage	Other	
2012				
Net operating revenues	\$133,150	\$6,679	\$39	\$139,868
Depreciation and amortization	16,338	1,612	-	17,950
Income from operations	75,964	2,679	23	78,666
Net income	39,791	806	10	40,607
Total assets at March 31, 2012	2,424,583	286,756	15,923	2,727,262
2011				
Net operating revenues	\$129,162	\$5,304	\$42	\$134,508
Depreciation and amortization	15,914	1,395	-	17,309
Income from operations	76,124	1,716	22	77,862
Net income	40,130	688	(45)	40,773
Total assets at March 31, 2011	2,304,731	244,403	22,419	2,571,553
Total assets at December 31, 2011	\$2,435,888	\$294,637	\$16,049	\$2,746,574

5. Common Stock

We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2012 to repurchase up to an aggregate of 2.8 million shares, but not to exceed \$100 million. No shares of common stock were repurchased pursuant to this program during the three months ended March 31, 2012. Since the plan's inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of \$83.3 million.

6. Stock-Based Compensation

We have several stock-based compensation plans, including a Long-Term Incentive Plan (LTIP), a Restated Stock Option Plan (Restated SOP) and an Employee Stock Purchase Plan. These plans are designed to promote stock ownership in NW Natural by employees and officers. For additional information on our stock-based compensation plans, see Note 6, in the 2011 Form 10-K and current updates provided below.

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Long-Term Incentive Plan

Performance-Based Stock Awards. On February 22, 2012, 35,340 performance-based shares were granted under the LTIP, which include a market condition, based on target-level awards and a weighted-average grant date fair value of \$53.92 per share. Fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following assumptions:

Stock price on valuation date	\$48.00
Performance term (in years)	3.0
Quarterly dividends paid per share	\$0.445
Expected dividend yield	3.6 %
Dividend discount factor	0.9012

Restricted Stock Units. A new form of restricted stock awards was approved by the Board in 2011. Restricted Stock Units (RSUs) are being used instead of the Restated SOP beginning in February of 2012. The current LTIP allows for a variety of awards including RSUs to be granted. RSUs include a performance based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of the RSU. On February 22, 2012, RSUs totaling 21,720 were granted with a grant date fair value of \$48.00 per share.

Restated Stock Option Plan

As of March 31, 2012, there was \$0.8 million of unrecognized compensation cost from grants of stock options in prior years, which is expected to be recognized over a period extending through 2014. No new stock options were granted in the three months ended March 31, 2012.

7. Cost and Fair Value Basis of Debt

Cost and Fair Value of Short-Term Debt

Our short-term debt consists of commercial paper and bank loans with an average maturity date of May 13, 2012 and an outstanding balance of \$113.7 million as of March 31, 2012. The fair value of our commercial paper approximates the amortized cost using Level 2 inputs.

Cost of Long-Term Debt

Our utility's long-term debt consists of secured Medium Term Notes (MTNs) with maturity dates ranging from 2014 through 2035, interest rates ranging from 3.176 percent to 9.05 percent, and a weighted-average coupon rate of 5.85 percent. During the three months ended March 31, 2012, we redeemed \$40 million of MTNs.

Our gas storage segment's long-term debt consists of \$40 million of fixed and variable senior secured notes with a maturity date of November 30, 2016. The \$20 million fixed portion of the debt has an interest rate of 7.75 percent, and the \$20 million variable portion currently has an interest rate of 7.00 percent. See Note 7 in our 2011 Form 10-K for more detail on long-term debt.

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Fair Value of Long-Term Debt

As our outstanding debt does not trade in active markets, we used interest rates of other companies' outstanding debt issuances that actively trade and have similar credit ratings, terms and remaining maturities to estimate the fair value of our long-term debt issuances. These inputs are significant other observable inputs, or Level 2 inputs, in the fair value hierarchy. The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

Thousands	March 31,		December 31,
	2012	2011	2011
Carrying amount	\$641,700	\$601,700	\$681,700
Estimated fair value	742,852	680,436	808,724

8. Pension and Other Postretirement Benefit Costs

The following tables provide the components of net periodic benefit cost for our company-sponsored qualified and non-qualified defined benefit pension plans and other postretirement benefit plans:

Thousands	Three Months Ended March 31,			
	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Service cost	\$2,130	\$1,899	\$177	\$168
Interest cost	4,304	4,527	314	344
Expected return on plan assets	(4,638)	(4,456)	-	-
Amortization of net actuarial loss	3,843	2,692	103	68
Amortization of prior service costs	49	88	49	49
Amortization of transition obligations	-	-	103	103
Net periodic benefit cost	5,688	4,750	746	732
Amount allocated to construction	(1,418)	(1,235)	(214)	(226)
Amount deferred to regulatory balancing account(1)	(2,068)	(1,330)	-	-
Net amount charged to expense	\$2,202	\$2,185	\$532	\$506

(1) Effective January 1, 2011, the Oregon Public Utility Commission (OPUC) approved the deferral of certain pension expenses above or below the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower pension expenses in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return.

Multiemployer and Defined Contribution Plans

In addition to the company-sponsored defined benefit pension plans referred to above, we contribute to a multiemployer pension plan (EIN 94-6076144) for our utility's bargaining unit employees, known as the Western States Office and Professional Employees Pension Fund (Western States Plan), and to defined contribution plans for utility and non-utility employees. The costs of these plans are in addition to pension expense in the table above. Our contributions to the Western States Plan amounted to \$0.1 million, and our contributions to the defined contribution plans amounted to \$0.7 million and \$0.8 million, for the three months ended March 31, 2012 and 2011, respectively. Under the terms of our current collective bargaining agreement, we can withdraw from the Western States Plan at any

time. However, if we withdraw and the plan is underfunded, we could be assessed a withdrawal liability. Currently, we have made no decisions to withdraw from the plan. Accordingly, we have not currently recognized these potential withdrawal liabilities on the balance sheet pursuant to accounting rules for multiemployer plans. See Note 9, in the 2011 Form 10-K for more information about these plans.

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Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

In the three months ended March 31, 2012, we made cash contributions totaling \$13.8 million to our qualified defined benefit pension plans. We also expect to make additional contributions of approximately \$14 million to these qualified plans over the last nine months of 2012, plus we expect to make ongoing benefit payments under our unfunded, non-qualified pension plans and other postretirement benefit plans.

9. Income Tax

The effective income tax rate for the three months ended March 31, 2012 and 2011 varied from the combined federal and state statutory tax rates principally due to the following:

	March 31,			
	2012		2011	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.6	%	4.6	%
Amortization of investment and energy tax credits	(0.3)) %	(0.4)) %
Differences required to be flowed-through by regulatory commissions	1.6	%	1.5	%
Gains on company and trust-owned life insurance	(0.4)) %	(0.2)) %
Other - net	0.2	%	0.1	%
Effective income tax rate	40.7	%	40.6	%

See Note 10 in our 2011 Form 10-K for more detail on income taxes and effective tax rates.

10. Property, Plant and Equipment

The following table sets forth the major classifications of our property, plant and equipment and accumulated depreciation as of March 31, 2012 and 2011 and December 31, 2011:

	March 31,		December
Thousands	2012	2011	31, 2011
Utility plant in service	\$2,342,681	\$2,264,055	\$2,323,467
Utility construction work in progress	34,903	28,464	36,051
Less: Accumulated depreciation	760,566	720,134	749,603
Utility plant-net	1,617,018	1,572,385	1,609,915
Non-utility plant in service	297,164	292,089	293,205
Non-utility construction work in progress	5,789	8,945	8,379
Less: Accumulated depreciation	19,117	13,505	17,623
Non-utility plant-net	\$283,836	\$287,529	\$283,961
Total property, plant and equipment	\$1,900,854	\$1,859,914	\$1,893,876

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11. Gas Reserves and Other Investments

Our gas reserves are stated at cost, net of volumetric regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Other investments include financial investments in life insurance policies, which are accounted for at fair value, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity or cost methods. See Note 12 in the 2011 Form 10-K for more detail on our investments.

Gas Reserves

We entered into agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop and produce physical gas reserves that are expected to supply a portion of NW Natural's utility customers' requirements over 30 years. Encana began drilling in 2011 under these agreements, and we are currently receiving gas from our interests in a section of the gas field. Our cost of gas and the carrying cost of the investment are included in our annual Oregon Purchased Gas Adjustment (PGA) filing and recovered through rates in a manner previously approved by the OPUC. This transaction accounted for approximately 2% of our gas supplies for the three month period ending March 31, 2012. The following table outlines our net investment at March 31, 2012 and 2011 and December 31, 2011:

Thousands	March 31, 2012	March 31, 2011	December 31, 2011
Gas reserves, current	\$6,732	\$-	\$4,463
Gas reserves, non-current	63,546	-	48,597
Less: Accumulated amortization	2,440	-	1,146
Total gas reserves	67,838	-	51,914
Less: Deferred taxes on gas reserves	22,047	-	15,630
Net investment in gas reserves	\$45,791	\$-	\$36,284

Variable Interest Entity (VIE) Analysis. We concluded that the arrangements with Encana qualify as a VIE, but that we are not the primary beneficiary of these activities as defined by the authoritative guidance related to consolidations. We account for our investment in the VIE on the cost basis and it is included under gas reserves on our balance sheet. Our maximum loss exposure related to the VIE is limited to our investment balance.

Palomar

PGH is a development stage variable interest entity. Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50 percent by NWN Energy and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Variable Interest Entity Analysis. As of March 31, 2012, we updated our VIE analysis and reconfirmed that we are not the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations due to the fact that we have a 50 percent share and there are no stipulations that allow disproportionate influence over the entity. Therefore, we account for our investment in PGH and the Palomar project under the equity method, which is included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our

equity investment balance, less our share of any cash or other assets available to us as a 50 percent owner.

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Impairment Analysis. Our investments in nonconsolidated entities accounted for under the equity method, including Palomar, are reviewed for impairment at each reporting period, and following updates to our corporate planning assumptions. When it is determined that a loss in value is other than temporary, a charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available, or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period. There have been no significant changes in carrying value or estimated fair value since year end.

Our investment balance in Palomar was \$13.5 million at March 31, 2012, which consists of costs related to the east segment. We are continuing to work on development of commercial support and Palomar expects to file a new Federal Energy Regulatory Commission (FERC) certification application to reflect a revised scope based on regional needs for the eastern segment of the proposed Palomar pipeline project. However, if we learn later that the project is not viable or will not go forward, we could be required to recognize a maximum charge of up to approximately \$13.2 million based on the current amount of our equity investment net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required. See Note 12 in our 2011 Form 10-K for more detail on Palomar and our annual impairment analysis.

12. Derivative Instruments

We enter into swap, option and combinations of option contracts for the purpose of hedging natural gas. We primarily use these derivative financial instruments to manage commodity prices related to our natural gas purchase requirements. A small portion of our derivative hedging strategy involves foreign currency exchange transactions related to purchases of natural gas from Canadian suppliers.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to these physical gas supply contracts. Derivatives entered into prudently for future gas years prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80 or a 90 percent deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10 or 20 percent recognized in current income. All of our commodity hedging for the 2011-12 gas year was completed prior to the start of the gas year, and these hedge prices were included in our PGA filing.

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The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments for the three months ended March 31, 2012 and 2011. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting standards.

Thousands	Three Months Ended			
	March 31, 2012		March 31, 2011	
	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
	(1)	(2)	(1)	(2)
Cost of sales	\$(55,894)	\$-	\$(33,750)	\$-
Other comprehensive income	-	126	-	602
Less:				
Amounts deferred to regulatory accounts on balance sheet	55,894	(126)	33,750	(602)
Total impact on earnings	\$-	\$-	\$-	\$-

(1) Unrealized gain (loss) from natural gas commodity hedge contracts is recorded in cost of sales and reclassified to regulatory deferral accounts on the balance sheet.

(2) Unrealized gain (loss) from foreign currency exchange contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet.

No collateral was posted with or by our counterparties as of March 31, 2012 or 2011. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and diversification, we have not been subject to collateral calls in 2011 or 2012. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current contracts outstanding, which reflect unrealized losses of \$55.8 million at March 31, 2012, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various downgrade credit rating scenarios for NW Natural as follows:

Thousands	Credit Rating Downgrade Scenarios					
	(Current Ratings)	A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	\$ -	\$-	\$12,785	\$6,805	\$40,441	
Without Adequate Assurance Calls	\$ -	\$-	\$-	\$4,292	\$32,928	

In the three months ended March 31, 2012 and 2011, we realized net losses of \$29.4 million and \$20.9 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas. The exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of our customers. For more information on our derivative instruments, see Note 13 in our 2011 Form 10-K.

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Fair Value

In accordance with fair value accounting, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation techniques include natural gas futures, volatility, credit default swap spreads and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at March 31, 2012. As of March 31, 2012 and 2011 and December 31, 2011, the fair value was a liability of \$55.8 million, \$33.1 million and \$61.0 million, respectively, using significant other observable, or Level 2, inputs. We have used no Level 3 inputs in our derivative valuations. We also did not have any transfers between Level 1 or Level 2 during the three months ended March 31, 2012 and 2011.

13. Commitments and Contingencies

Environmental Matters

We own, or previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study and evaluate the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated.

We regularly review our environmental liability for each site where we may be exposed to remediation responsibilities, but the costs 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. Site investigations and remediation efforts often develop slowly over many years. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course and scope of the effort and ultimately also the cost. Many of these steps are dependent upon the approval and direction of federal and state environmental regulators whose policies, determinations and directions may change over time creating further uncertainty as to the timing and scope of remediation activities. In certain cases there are a number of other potentially responsible parties in addition to us, each of which may influence the course and scope of the remediation effort. The allocation of liabilities among the potentially responsible parties is subject to dispute and uncertainty at this time with respect to the sites noted below. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

We estimate the range of loss for 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 an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the lower end of this range. It is likely that changes in these estimates and ranges 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 determination by regulators of remediation alternatives. The status of each of the sites currently under investigation is provided below.

Portland Harbor site. In 1998, the Oregon Department of Environmental Quality (ODEQ) and the Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor). Since then, EPA has extended the Portland Harbor site to approximately 11 miles of the Willamette River. The Portland Harbor site is adjacent to two upland sites owned by NW Natural that are discussed below as the Gasco upland and Siltronic upland sites. The Portland Harbor was listed by the EPA as a Superfund site in 2000, and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties (the Lower Willamette Group or LWG) to fund the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). The LWG submitted the draft Final Portland Harbor Remedial Investigation to EPA in 2011. The LWG submitted the draft Feasibility Study (FS) to EPA in March 2012. The EPA will use the information in the RI/FS to select a cleanup plan for the Portland Harbor Superfund Site. The draft FS provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is \$169 million to \$1.8 billion. NW Natural's potential liability is a portion of the costs of the remedy EPA ultimately selects for the entire Portland Harbor Superfund site. The costs of that remedy is expected to be allocated among more than 100 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability.

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Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with EPA to evaluate and design specific remedies for sediments adjacent to the Gasco upland and Siltronic upland sites, discussed below. The Gasco/Siltronic Sediments is part of the Portland Harbor Superfund site. NW Natural intends to submit a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. The EE/CA will provide a variety of remedial alternatives for the sediments at this site. The alternatives provided in the EE/CA are based on EPA requirements to develop costs for the various remedies described therein. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA range from \$34 million to \$350 million. After the EPA determines an appropriate alternative from the EE/CA, a remedial design will be produced. We have recorded a liability of \$34.0 million for the sediment clean-up, which reflects the low end of the EE/CA range. We have recorded an additional liability of \$12.1 million for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight through the clean-up. At this time, we believe the sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above. We accrued at the low end because no amount within the range is considered to be more likely than another.

Portland Harbor RI/FS and natural resource damage claims. NW Natural incurs costs related to our membership in the Lower Willamette Group which is performing the RI/FS for EPA. NW Natural also incurs costs related to natural resource damages. In 2008, the Portland Harbor Natural Resource Trustee Council advised a number of potentially responsible parties that it intended to pursue natural resource damage claims at the Portland Harbor Superfund Site. The Company and other parties have signed a cooperative agreement with the Natural Resource Trustees to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. As of March 31, 2012, we have an accrued liability of \$4.9 million for these claims, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated at this time. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

Gasco upland site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site). The Gasco upland site is adjacent to the Portland Harbor site described above and has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site. In June 2003, we filed a Feasibility Scoping Plan which outlined a range of remedial alternatives for the most contaminated portion of the Gasco upland site. In December 2004, we submitted an Ecological and Human Health Risk Assessment to ODEQ, and in May 2007 we completed a revised Remedial Investigation Report and submitted it to ODEQ for review. The liability accrued at March 31, 2012 for the Gasco upland site is \$9.3 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

In 2007, we also submitted a Focused Feasibility Study (FFS) for the groundwater source control portion of the Gasco site, which ODEQ conditionally approved in March 2008, subject to the submission of additional information. We provided that information to ODEQ and are now working with the agency on the final design for the source control system. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding remediation, we have estimated a range of liability between \$11 million and \$30 million, for which we have recorded an accrued liability of \$11.6 million at March 31, 2012. The estimated range of liability will be reassessed when ODEQ makes a final source control design decision.

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Siltronic upland 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 upland site). The Siltronic upland site is also adjacent to the Portland Harbor site, but not included in the range of remedial costs for the Portland Harbor site. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The liability accrued at March 31, 2012 for the Siltronic site is \$1.1 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2008, we received notice that this site was added to the ODEQ's list of sites in which releases of hazardous substances have been confirmed. ODEC has also added this site to its list of sites where cleanup is necessary. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. As of March 31, 2012, we have a liability accrued of \$0.4 million for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. It is near but outside the geographic scope of the current Portland Harbor site sediment studies. The EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that it could be managed separately from the Portland Harbor site under ODEQ authority. Work plans for source control investigation and a historical report were submitted to ODEQ and initial studies were completed. In 2010, ODEQ required additional studies which are underway. As of March 31, 2012, we have an estimated liability accrued of \$1.5 million for the study of the sediments and riverbank groundwater and soils at the site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Oregon Steel Mills site. See "Legal Proceedings," below.

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Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at March 31, 2012 and 2011 and December 31, 2011:

Thousands	Current Liabilities			Non-Current Liabilities		
	Mar. 31, 2012	Mar. 31, 2011	Dec. 31, 2011	Mar. 31, 2012	Mar. 31, 2011	Dec. 31, 2011
Portland Harbor site:						
Gasco/Siltronic Sediments	\$2,459	\$1,049	\$1,614	\$43,655	\$29,996	\$35,797
Other Portland Harbor	1,400	2,314	1,893	3,547	5,829	7,066
Gasco site	13,197	12,574	14,092	7,689	6,103	8,900
Siltronic upland site	478	730	887	588	291	128
Central Service Center site	-	5	-	424	501	495
Front Street site	1,131	-	1,697	395	947	-
Other sites	-	-	-	116	117	120
Total	\$18,665	\$16,672	\$20,183	\$56,414	\$43,784	\$52,506

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC granted us additional authorization to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and interest accrual has been extended through January 2013. In addition, beginning in 2011, the Washington Utilities and Transportation Commission (WUTC) authorized the deferral of certain environmental costs associated with services provided to Washington customers. Environmental costs related to Washington are being deferred as of January 26, 2011 with cost recovery to be determined in a future proceeding.

On a cumulative basis, we have recognized a total of \$129.7 million for environmental costs, including legal, investigation, monitoring and remediation costs, and \$4.9 million paid and expensed prior to regulatory deferral order approval. At March 31, 2012, we had a regulatory asset of \$112.3 million.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Item 3. Legal Proceedings in the 2011 Form 10-K). NW Natural seeks damages in excess of \$50 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future. In December 2011, NW Natural reached a settlement with Associated Electric and Gas Insurance Services Limited and dismissed its claims against that insurer in the litigation.

Our regulatory recovery of environmental cost deferrals may be initiated when rates go into effect for the Oregon general rate case; however, because the rate case proceeding is ongoing, and because the ultimate amounts collected will depend upon future insurance recoveries and future expenditures, we are not currently able to estimate the amount of recovery expected through the implementation of new rates.

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Legal Proceedings

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

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

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

The following is management's assessment of Northwest Natural Gas Company's (NW Natural) financial condition, including the principal factors that affect results of operations. The disclosures contained in this report refer to our consolidated activities for the three months ended March 31, 2012 and 2011. Unless otherwise indicated, references below to "Notes" are to the Notes to Consolidated Financial Statements in this report. A significant portion of our business results are seasonal in nature, and as such the results of operations for this three month period are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2011 Annual Report on Form 10-K (2011 Form 10-K).

The consolidated financial statements include the accounts of NW Natural and its direct and indirect wholly-owned subsidiaries which include: NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch) and NNG Financial Corporation (NNG Financial). These statements also include accounts related to our equity investment in Palomar Gas Holdings, LLC (PGH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary Palomar Gas Transmission LLC (Palomar). These accounts make up our regulated local gas distribution business, our regulated gas storage businesses, and other regulated and non-regulated investments primarily engaged in energy-related businesses. In this report, the term "utility" is used to describe our regulated gas distribution business (local distribution company), and the term "non-utility" is used to describe our regulated gas storage businesses (gas storage) as well as our other regulated and non-regulated investments and business activities (other). For further information on our business segments, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain financial 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 consolidated earnings. All references in this section to earnings per share are on the basis of diluted shares (see Part II, Item 8., Note 3, "Earnings Per Share," in our 2011 Form 10-K). We use such non-GAAP measures (i.e. measures not based on generally accepted accounting principles) in analyzing our financial performance and believe that they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

Executive Summary

Highlights of consolidated results for the first quarter of 2012 as compared to the same period in 2011 include:

- Consolidated net income of \$40.6 million or \$1.51 per share in the first quarter of 2012, as compared to \$40.8 million or \$1.53 in the first quarter of 2011;
- Net income from utility operations decreased \$0.3 million, from \$40.1 million in 2011 to \$39.8 million in 2012;
- Net income from gas storage operations increased \$0.1 million, from \$0.7 million in 2011 to \$0.8 million in 2012;
- Net operating revenues (margin) increased \$5.4 million or 4 percent over 2011, with utility margin up \$4.0 million and gas storage margin up \$1.4 million;
- Operating expenses increased \$4.6 million or 8 percent over 2011, primarily due to higher operations and maintenance expense and higher general tax expense;

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- Interest expense increased \$0.7 million or 7 percent over 2011 due to senior secured notes issued by Gill Ranch late in 2011;
- Cash flow from operating activities was \$114.1 million, an increase of \$6.0 million or 6 percent over the same period in 2011;
- Utility customers increased by approximately 5,300 over the last 12 months, for an annual growth rate of 0.8 percent compared to 0.9 percent a year ago; and
- NW Natural was ranked as the top gas utility in the West, and second highest in the nation, in the 2012 J.D. Power & Associates Business Customer Satisfaction Survey.

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Issues, Challenges and Performance Measures

Economic environment. Weakness in local, national and global economies continues to impact utility customer growth, business demand for natural gas and market prices for gas storage. Our utility's customer growth rate remained relatively flat for the third year in a row, with an annual growth rate of 0.8 percent for the period ended March 31, 2012, compared to 0.8 percent for March 31, 2011 and 0.7 percent for March 31, 2010. The local economy is beginning to show signs of a slow recovery, with unemployment rates in Oregon and southwest Washington declining from over 10 percent during 2011 to under 9 percent early in 2012, and with industrial usage of natural gas increasing 4 percent in 2012 over 2011. We believe our utility is well positioned to add customers and to serve increasing industrial demand as the economy recovers because of low and stable natural gas prices, our relatively low market penetration, our focus on converting homes and businesses to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

Managing gas prices and supplies. Our gas acquisition and management strategy is to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so that we can effectively manage costs, reduce price volatility for customers, and maintain a competitive advantage. With recent developments in drilling technologies and substantial access to gas supplies from shale formations around the U.S. and in Canada, the current outlook for North American natural gas supply is strong and should remain that way well into the future. The abundance of gas suggests continued lower and more stable gas prices, subject to a regulatory environment that continues to support hydraulic fracturing and other drilling technologies.

Our utility's Purchased Gas Adjustment (PGA) mechanisms in Oregon and Washington, along with our gas price hedging strategies which include gas reserves and gas storage inventories, enable us to reduce earnings exposure for the company and secure lower gas costs for customers. These lower gas prices, coupled with our focus on customer service and cost-effective energy efficiency programs, can help strengthen natural gas' competitive advantage over other energy sources in key markets.

Each year we typically hedge about 75 percent of our utility's annual sales requirements based on normal weather. For the current gas contract year (November 1, 2011 – October 31, 2012), we were roughly 51 percent hedged with financial swap and option contracts and 24 percent hedged with physical gas supplies. The physical supplies consisted of a combination of gas inventories in storage, gas production from the Mist area which we buy at pre-determined prices, and gas production from an investment we made in gas reserves with Encana Oil & Gas (USA) Inc. (Encana). The gas reserves with Encana relate to a new investment we made beginning in 2011, whereby we own working interests in certain leases in Encana's Jonah gas field located in Rock Springs, Wyoming. For a further discussion of gas reserves, see "Investments in Gas Reserves" under "Strategic Opportunities" below and "Gas Reserves" under "Rate Mechanisms" below.

Besides the amount hedged for the current gas contract year, we are also hedged at approximately 32 percent for the 2012-13 gas year and between 9 and 14 percent hedged for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather and economic conditions. In addition, our storage inventory levels may increase or decrease based on storage expansion or storage recall by the utility. The Company added approximately 1 Bcf to its off-system storage capacity by entering into a 3-year contract with a third-party for natural gas storage located in Canada. Injections are scheduled to begin April 2012. We expect recovery of our demand charges and other costs through our normal PGA mechanism. As for gas reserves, these levels are estimates of production, which are subject to change based on possible unforeseen events including the impact from the pace of drilling activity and the volume of production from each well.

Although less expensive and more stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Consequently, our ability to sign longer-term storage contracts with customers at favorable prices affects our ability to improve financial results, but we remain committed to find opportunities for lowering costs and to develop enhanced services for customers.

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Environmental clean-up costs. We continue to accrue all material loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the development of remediation solutions approved by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we have been allowed to defer certain costs pursuant to regulatory decisions. We currently have regulatory authority to defer certain environmental costs, and to seek recovery of those costs in future customer rates. However, we are expected to pursue recovery from insurance policies first, and to seek recovery from customers only for amounts not recovered from insurance. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage costs and demonstrate that costs were prudently incurred. Recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable.

See Results of Operations—Regulatory Matters—Rate Mechanisms—Regulatory Recovery for Environmental Costs below, Note 13 in this report and Note 15 in our 2011 Form 10-K.

Performance measures. In order to deal with the challenges affecting our businesses, we annually review and update our strategic plan to map out a course for the next several years. Our plan includes: further improving our utility gas distribution system; enhancing utility services and operations; optimizing and growing our non-utility gas storage businesses; investing in natural gas infrastructure projects when necessary to support the energy needs of our region; and maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support clean energy technologies. We intend to measure our performance and monitor progress on relevant metrics including, but not limited to: earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction ratings; utility margin; utility capital and operations and maintenance expense per customer; and earnings before interest, taxes, depreciation and amortization (EBITDA).

Strategic Opportunities

Business process improvements. We continue to evaluate, develop and implement business strategies to improve operational efficiencies and respond to economic and competitive challenges. Over the past several years, we focused our efforts on developing, integrating, consolidating and streamlining operations, while supporting our employees with new training and new technology tools.

Since 2006, we reduced staffing levels in response to work load declines related to the low customer growth environment and efficiency improvements, resulting in a reduction of full-time, utility positions from over 1,300 in early 2006 to about 1,050 at the end of 2011. Technology investments, workforce reductions and other initiatives have contributed to a significant increase in efficiency. We also continue to improve the quality and integrity of our buildings and pipeline infrastructure. The number of utility customers served per operating employee increased by 32 percent, from 738 at the end of 2005 to 975 at the end of 2011. We expect these efforts to contribute to long-term operational efficiencies and lower operating and capital costs throughout NW Natural. We remain committed to increasing shareholder value and we continue to look for new ways to improve our business effectiveness as service demands and federal safety requirements increase.

Gas storage development. We currently own and operate two underground gas storage facilities—the Mist facility in Oregon and the Gill Ranch facility in Fresno, California. Our Mist facility currently consists of 16 Bcf of available storage capacity, with 10 Bcf allocated to the utility business and 6 Bcf allocated to the gas storage business. Our

wholly-owned subsidiary, Gill Ranch, holds a 75 percent undivided ownership interest in the Gill Ranch facility; Pacific Gas and Electric Company (PG&E) owns the other 25 percent interest. Currently, we have 15 Bcf of available storage capacity for the gas storage business, along with 27 miles of gas transmission pipeline capacity connecting the Gill Ranch facility to an interconnect on PG&E's transmission system. Future expansion is possible at both the Mist and Gill Ranch storage facilities. For more information, see Note 4 in this report and Part II, Item 7., "2012 Outlook—Strategic Opportunities," in our 2011 Form 10-K.

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Due to an abundant supply of natural gas and lower, more stable prices in North America, storage values are expected to remain relatively low in the near term, which will likely affect the prices at which Gill Ranch is able to contract. Gas prices recently hit a 10-year low, and this has resulted in certain natural gas producers reducing their levels of exploration and production. At the same time, we expect these lower gas prices to increase demand for natural gas as the lower pricing provides a competitive advantage over alternative energy sources including the potential demand for exporting natural gas. Combined, these forces may ultimately result in upward pressure on gas prices and return some price volatility to natural gas markets.

Our storage facilities position us well to capitalize on rising demand for natural gas, increasing gas prices or greater market volatility because storage operations benefit from seasonal swings in commodity prices and market volatility. Additionally, if market demand increases and we are able to obtain regulatory permits and project financing, we have the ability to expand the Gill Ranch facility beyond its current capacity without further expansion of our gas transmission pipeline. We estimate that the current Gill Ranch storage facility could support an aggregate storage capacity of around 40 Bcf with certain infrastructure modifications, of which we would have the rights to 50 percent of the total.

The Pacific Northwest storage markets also are impacted by lower gas prices and lack of gas price volatility, although less than California markets primarily because of fewer regional competitors. Nevertheless, we continue to plan for expansion of our gas storage facilities at Mist in anticipation of increased natural gas demand for electric generation in the Pacific Northwest. Currently we do not have a set timeline for development, but we believe the earliest timeframe for completing the next Mist expansion is 2016. In the meantime, we expect to continue working on preliminary design and scope of the next expansion, which will likely include the development of storage wells, a second compression station and additional pipeline gathering facilities that would enable not only the next expansion but future expansions as well.

Pipeline diversification. Currently, our utility operations and gas storage operations at Mist depend on a single bi-directional interstate transmission pipeline to ship customer supplies. Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a gas transmission pipeline that would provide a new interconnection with our utility distribution system. PGH is owned 50 percent by our NWN Energy subsidiary and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. The Palomar pipeline was originally proposed with an east and a west segment, but currently Palomar's plan is to design and develop an east-only pipeline to serve our utility customers as well as growing natural gas markets in Oregon and other parts of the Pacific Northwest.

Palomar has negotiated a non-binding memorandum of understanding (joint agreement) with The Williams Companies' Northwest Pipeline (Northwest Pipeline), which contemplates Northwest Pipeline becoming a part owner in the Palomar project. This joint agreement would consolidate the region's efforts to develop a cross-Cascades pipeline around the use of the Palomar route. Northwest Pipeline is the owner and operator of the single bi-directional interstate transmission pipeline that connects with NW Natural's utility distribution system.

The proposed Palomar pipeline would be regulated by Federal Energy Regulatory Commission (FERC). In March 2011, Palomar withdrew its original application with FERC, but at the same time informed FERC that it intended to file a new application with a modified scope that excluded the western segment, after it has conducted a new open season to obtain commercial support for the eastern segment. The timing for construction of the Palomar pipeline is expected depends on regulatory permits and determining commercial support from shippers.

Gas reserves. In addition to hedging gas prices with financial swap and option contracts, we signed an agreement with Encana in 2011 to acquire physical gas supplies to meet a portion of our utility customers' requirements over 30

years. During the first 10 years, we forecast the volumes of gas received under the Encana agreement to provide approximately 8 to 10 percent of the average annual requirements of our utility customers. Under the agreement, we expect to invest approximately \$45 million to \$55 million per year for five years, subject to certain NW Natural rights to terminate the agreement, with our total investment expected to be about \$250 million. We pay a fixed portion of drilling costs per well, and Encana assigns to us working interests in leases to certain sections of the Jonah gas field, located near Rock Springs, Wyoming. These sections include both future and currently producing wells. The working interests entitle us to receive a portion of the gas produced in the assigned sections. Operation of the wells are governed by a joint operating agreement under which Encana is the operator, and we pay our proportionate share of the operating costs. See Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves below and Part II, Item 7., “2012 Outlook—Strategic Opportunities,” in our 2011 Form 10-K.

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Consolidated Earnings and Dividends

The primary factors contributing to the decrease in first quarter consolidated net income were:

- a \$5.4 million increase in net operating revenue (margin) primarily due to an increase from the utility's residential and commercial customers, an increase from the utility's incentive sharing related to gas cost savings, and an increase from gas storage at Gill Ranch;
 - a \$3.2 million increase in operations and maintenance expense primarily related to increases in utility payroll, utility employee benefit costs, utility training costs, and Oregon rate case expenses;
 - a \$0.7 million increase in general taxes, primarily related to Gill Ranch property taxes;
- a \$0.7 million increase in depreciation and amortization related to capital asset additions at both the utility and Gill Ranch; and
- a \$0.7 million increase in interest expense primarily related to the new debt issuance at Gill Ranch in late 2011.

Dividends paid on our common stock were 44.5 cents per share in the first quarter of 2012, compared to 43.5 cents per share in the first quarter of 2011. The Board of Directors declared a quarterly common stock dividend of 44.5 cents per share, payable on May 15, 2012, to shareholders of record on April 30, 2012. The current indicated annual dividend rate is \$1.78 per share.

Application of Critical Accounting Policies and Estimates

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

- regulatory cost recovery and amortizations;
 - revenue recognition;
- derivative instruments and hedging activities;
 - pensions and postretirement benefits;
 - income taxes; and
 - environmental contingencies.

There have been no material changes to the information provided in the 2011 Form 10-K with respect to the application of critical accounting policies and estimates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates," in the 2011 Form 10-K). For an update of environmental disclosures see Note 13.

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 2.

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Results of Operations

Regulatory Matters

Regulation and Rates

Utility. Our utility business is subject to regulation with respect to, among other matters, rates and systems of accounts set by the Oregon Public Utility Commission (OPUC), Washington Utilities and Transportation Commission (WUTC), and FERC. The OPUC and WUTC also regulate the issuance of securities by our utility. In 2011, approximately 90 percent of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 10 percent from Washington customers. Future earnings and cash flows from utility operations will largely be determined by rate cases in Oregon and Washington, but will also be affected by the economies in Oregon and Washington, by the pace of customer growth in the residential and commercial markets, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets.

Gas Storage. Our gas storage business is subject to regulation with respect to, among other matters, issuance of securities and systems of accounts set by the OPUC, California Public Utilities Commission (CPUC), and FERC. The OPUC and FERC regulate our Mist gas storage business under a maximum cost-based rate model, whereas the CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2011, approximately 65 percent of our storage revenues were derived from OPUC and FERC approved cost-based rates, and approximately 35 percent were from California approved market-based rates.

See Part II, Item 7., “Results of Operations—Regulatory Matters,” in the 2011 Form 10-K.

Oregon General Rate Case

On December 30, 2011, we filed an application for a general rate increase with the OPUC. In the filing, we requested an increase in authorized annual Oregon jurisdictional revenues of \$43.7 million, equivalent to a rate increase of 6.2 percent. The amount and percent of the requested rate increase includes an estimated \$15.1 million that represents the cumulative effect of declining use per customer. This amount is currently recovered in customers’ rates through the Company’s conservation tariff mechanism, which has been in place since 2003. Our requested increase also includes costs related to pension contributions and additional utility services. The filing also requests an authorized overall rate of return on capital of 8.28 percent, with a return on common stock equity (ROE) of 10.3 percent and a capital structure of 50 percent common equity. In addition, we have requested the establishment of rate recovery mechanisms for deferred costs related to our environmental liabilities. The filing also requests rate redesign for residential customers with a higher fixed fee, which would effectively combine and incorporate the effects of the weather normalization and decoupling tariffs in the new fixed fee amount. The new rates are requested to be effective by November 1, 2012.

On May 3, 2012, several parties involved in NW Natural’s general rate case filed their testimony, which represents their first filing in the formal administrative proceeding through which the OPUC determines rate cases. These included the Staff of the OPUC, the Citizen’s Utility Board (CUB), and the Northwest Industrial Gas Users (NWIGU). In its testimony, the OPUC Staff recommended a revenue requirement reduction of \$10.7 million, or 1.5 percent,

compared to our requested \$43.7 million increase. Staff's testimony is based on a 7.56 percent overall cost of capital including a 9.2 percent return on common equity, and reductions to various operation and maintenance (O&M) expenses and capital additions requested. These parties also recommended certain modifications to our proposed environmental cost recovery mechanism, modifications to an existing allocation of revenues to customers from our interstate gas storage operations and denial of our request for recovery of certain costs related to our contributions covering employee pension benefits. The filings made by CUB and NWIGU overlap with Staff's proposals in some areas while also recommending additional reductions to O&M and capital additions. The Company disagrees with the recommendations made and will be filing testimony rebutting these recommendations in June.

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Throughout the formal administrative proceeding, NW Natural and the parties have the opportunity to engage in settlement discussions regarding any or all of the issues involved in the proceeding. We have engaged in such discussions during scheduled settlement conferences. We are unable at this time to predict the outcome of this rate proceeding, or to predict which, if any, issues will be presented to the OPUC as part of a contested proceeding or as part of a settlement proposal.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories and gas reserves, interstate pipeline demand costs, the application of temporary rate adjustments which amortizes balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

Effective November 1, 2011, the OPUC and WUTC approved PGA rate changes to decrease the average monthly bills of Oregon and Washington residential customers by 2 percent. This was our third consecutive year of PGA rate decreases, and cumulatively our average utility residential customer bills declined 20 percent in Oregon and 26 percent in Washington since 2008.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80 percent or 90 percent deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20 percent or 10 percent of the difference between actual and estimated gas costs, respectively. Under the Washington PGA mechanism, we defer 100 percent of the higher or lower actual gas costs, and those gas cost differences are normally passed on to customers through the annual PGA rate adjustment. See “Customer Credits for Gas Cost Incentive Sharing” below for a discussion of our utility’s early refund proposal to customers of deferred gas cost savings from November 1, 2011 through March 31, 2012.

In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings test to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for the 2009-10, the 2010-2011 and the 2011-2012 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2010 and 2011, the ROE threshold after adjustment for long-term interest rates was 11.02 percent and 10.92 percent, respectively. We refunded \$0.2 million to customers in the current PGA for the 2010 utility earnings test. Based on utility results for 2011 we accrued an amount for potential refund to customers in the future PGA’s.

Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue a carrying cost on environmental costs paid, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and accrual of carrying costs was extended through January 2013. See Note 13 for further discussion of our regulatory and insurance recovery of environmental costs.

The WUTC has also authorized the deferral of environmental costs, if any, that are incurred in connection with services provided to Washington customers. The order granting approval of that request was effective January 26, 2011.

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Pension Deferral. Effective January 1, 2011, the OPUC approved our request to defer the annual accounting expense for qualified defined benefit pension plans above the amount set in rates in our last general rate case. The recovery of these deferred pension costs will be through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return, which is currently 8.62 percent. The reduction to operations and maintenance expense in 2011 was \$6.0 million. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities using a number of key assumptions, as well as being affected by pension contributions by the company. We estimate pension expense deferrals totaling \$8 million to \$9 million in 2012, with \$2.1 million being deferred for the three months ended March 31, 2012.

Customer Credits for Gas Cost Incentive Sharing. For the period between November 1, 2011 and March 31, 2012, our actual gas costs were significantly lower than the gas costs currently embedded in customer rates. As a result, our PGA incentive sharing mechanism recorded 90 percent of gas cost savings during this period, attributed to Oregon customers, and 100 percent of the savings attributed to Washington customers to a regulatory account for credit to customers (see "Purchased Gas Adjustment," above). Ordinarily, these credits would be included in customer rates starting in November under the next year's PGA filing, but in April 2012 the company requested regulatory approval to immediately refund \$35.1 million and \$4.2 million to our Oregon and Washington customers, respectively, through billing credits. If approved, we intend to credit these amounts to customer bills starting in June of 2012.

Customer Credits for Gas Storage Sharing. In April 2012, the company requested regulatory approval to provide its Oregon utility customers with a \$9.2 million interstate storage credit from our regulatory incentive sharing mechanism related to interstate gas storage and asset management services. If approved, we intend to credit this amount to customer bills starting in June of 2012.

For a discussion of other rate mechanisms, including but not limited to our system integrity program, see Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2011 Form 10-K.

Business Segments - Utility Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather and customers' gas usage patterns because a significant portion of our margin revenues are derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff, which adjusts margin revenues to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, which adjusts customer bills up or down to offset changes in margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of our utility's earnings and customer charges. For more information on our conservation and weather normalization tariffs, see discussion under "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2011 Form 10-K.

For the three months ended March 31, 2012, utility operations contributed net income of \$39.8 million or \$1.48 per share, compared to \$40.1 million or \$1.50 per share for the same period of 2011. Total utility volumes sold and delivered for the three months ended March 31, 2012 increased by 2 percent compared to the same period for 2011 primarily due to an increase in all three customer categories (i.e. residential, commercial and industrial). Total utility margin increased by \$4 million, or 3 percent primarily due to increases in residential and commercial customer margins totaling \$1.7 million, including the effects of conservation and weather normalization adjustments, and an increase in gas cost incentive sharing gains of \$1.6 million.

Our weather normalization mechanism adjusted residential and commercial margins down by \$3.8 million in the three months ended March 31, 2012 based on temperatures that were 4 percent colder than average, compared to a margin decrease of \$5.9 million last year when temperatures were 6 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins up by \$6.7 million in the three months ended March 31, 2012, compared to a margin increase of \$8.7 million in the comparable period last year.

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The following table summarizes the composition of gas utility volumes, revenues and margin. Certain amounts in prior year balances under the utility margin section of the table have been reclassified to conform with the current year's presentation. These reclassifications reflect amounts moved from other margin adjustments into residential, commercial and industrial categories where amounts were assignable to a specific customer category. Utility margin in total was not affected by the reclassifications.

Thousands, except degree day and customer data	Three Months Ended March 31,		Favorable/ (Unfavorable) 2012 vs. 2011
	2012	2011	
Utility volumes - therms:			
Residential sales	176,037	174,704	1,333
Commercial sales	100,122	99,177	945
Industrial - firm sales	10,619	10,864	(245)
Industrial - firm transportation	38,851	36,482	2,369
Industrial - interruptible sales	17,730	17,237	493
Industrial - interruptible transportation	64,800	62,950	1,850
Total utility volumes sold and delivered	408,159	401,414	6,745
Utility operating revenues - dollars:			
Residential sales	\$ 194,839	\$ 198,837	\$ (3,998)
Commercial sales	92,175	94,768	(2,593)
Industrial - firm sales	8,309	8,845	(536)
Industrial - firm transportation	1,908	1,746	162
Industrial - interruptible sales	10,048	10,327	(279)
Industrial - interruptible transportation	2,046	2,316	(270)
Regulatory adjustment for income taxes paid(1)	-	286	(286)
Other revenues	1,435	602	833
Total utility operating revenues	310,760	317,727	(6,967)
Cost of gas sold	169,755	180,610	10,855
Revenue taxes	7,855	7,955	100
Utility margin	\$ 133,150	\$ 129,162	\$ 3,988
Utility margin:(2)			
Residential sales	\$ 85,608	\$ 84,252	\$ 1,356
Commercial sales	32,965	32,558	407
Industrial - sales and transportation	7,636	7,610	26
Miscellaneous revenues	1,595	1,584	11
Gain from gas cost incentive sharing	2,637	1,035	1,602
Other margin adjustments	(133)	(1,027)	894
Margin before regulatory adjustments	130,308	126,012	4,296
Weather normalization adjustment	(3,815)	(5,861)	2,046
Decoupling adjustment	6,657	8,725	(2,068)
Regulatory adjustment for income taxes paid(1)	-	286	(286)
Utility margin	\$ 133,150	\$ 129,162	\$ 3,988
Customers - end of period:			
Residential customers	617,665	612,738	4,927
Commercial customers	63,210	62,800	410
Industrial customers	919	908	11

Total number of customers - end of period	681,794	676,446	5,348
Actual degree days	1,954	1,974	
Percent colder than average weather(3)	4 %	6 %	

- (1) Regulatory adjustment for income taxes paid is described below.
- (2) Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.
- (3) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

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Residential and Commercial Sales

The primary changes that impacted margin from residential and commercial sales for the three months ended March 31, 2012 compared to March 31, 2011 were as follows:

- utility sales volumes were 1 percent higher, primarily reflecting residential and commercial customer growth of 0.8 percent and increased demand from customers;
- utility operating revenues decreased \$6.6 million or 2 percent primarily due to lower customer billing rates tied to PGA prices decreases, partially offset by higher volumes; and
- utility margin increased \$1.7 million or 1 percent primarily reflecting increased volumes from higher residential and commercial sales volumes due to customer growth.

Industrial Sales and Transportation

The primary changes that impacted volumes and margins from industrial sales and transportation services for the three months ended March 31, 2012 compared to March 31, 2011 were as follows:

- gas deliveries to industrials were up about 4 percent in the quarter over 2011 results. The volume increase in the period reflects a slight improvement in the economy. Specifically, we've added a few new customers in the forest products segment, and because of the price advantage of natural gas over oil we are beginning to see asphalt plants and other businesses converting to gas that we believe will be coming online in the second and third quarters; and
- margin from industrial customers was flat compared to last year, with increases in usage and margins from the manufacturing sector offset by margin losses from customers no longer in business or scaled back due to the weak economy.

Regulatory Adjustment for Income Taxes Paid

In prior years, Oregon law required the company to annually review the amount of income taxes collected in rates from utility operations and compare it to the amount of taxes the utility paid. In 2011, this law was repealed. We did not recognize any income or expense related to this regulatory adjustment for the three months ended March 31, 2012, but we did recognize margin revenues of \$0.3 million in the three months ended March 31, 2011 for accrued interest attributed to regulatory surcharges related to the 2009 and 2010 tax years. For more information on regulatory income taxes paid, see Results of Operations – Business Segments – Utility Operations – Regulatory Adjustment for Income Taxes Paid in our 2011 Form 10-K.

Other Revenues

Other revenues include miscellaneous fee income and other regulatory adjustments. Other revenues increased from \$0.6 million for the three months ended March 31, 2011 to \$1.4 million for the three months ended March 31, 2012. The majority of this difference is related to the charge taken related to the earnings test, which was \$1.0 million in the first quarter of 2011 and \$0.4 million in the first quarter of 2012.

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Cost of Gas Sold

Cost of gas sold as reported by the utility includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, production from gas reserves, and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the same costs are incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism whereby we either increase or decrease margin results based on a percentage of actual gas costs as compared to embedded gas costs in the PGA. Under this provision, our net income can be affected by differences between actual and expected gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases (see “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment,” above). In addition, we recently entered into a regulatory agreement where we receive a rate base return on our investment in gas reserves (see Part II, Item 7., “Regulatory Matters-Rate Mechanisms-Purchased Gas Adjustment and Regulatory Matters-Rate Mechanisms-Gas Reserves in the 2011 Form 10-K). We use natural gas commodity-based hedge contracts (derivatives), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage our exposure to rising gas prices. Gains and losses from these financial hedge contracts are generally included in our PGA prices and normally do not impact net income because the hedged prices are reflected in our annual rate changes, subject to a regulatory prudence review. However, hedge contracts entered into after the annual PGA rates are set in Oregon can impact net income because we would be required to share in any gains or losses as compared to the corresponding commodity prices built into rates in the PGA. In Washington, 100 percent of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates (see Part II, Item 7., “Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities,” and “Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment,” in the 2011 Form 10-K, and Note 12 in this report). The following summarizes the major factors that contributed to changes in cost of gas sold for the three months ended March 31, 2012:

- total cost of gas sold decreased \$10.9 million, or 6 percent, due to a 7 percent decrease in the average cost of gas sold per therm offset by a 2 percent increase in sales volumes and;
- the average gas cost collected through rates decreased from 60 cents per therm in the first quarter of 2011 to 56 cents per therm in the first quarter of 2012, primarily reflecting lower gas prices, which were passed on through PGA rate decreases effective November 1, 2011; and
- hedge losses totaling \$29.4 million were realized and included in cost of gas sold for the three months ended March 31, 2012, compared to \$20.9 million of hedge losses in the same period of 2011. Since the underlying hedge prices were included in our PGA billing rates, these losses did not impact margin or net income.

The amount recorded to pre-tax income from the shareholders’ portion of our gas cost incentive sharing mechanism was a margin contribution of \$2.6 million in the three months ended March 31, 2012 compared to \$1.0 million in 2011. For a discussion of our gas cost incentive sharing mechanism, see “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment,” above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our ownership interest in the Gill Ranch underground storage facility in California. For the three months ended March 31, 2012, our gas storage segment earned \$0.8 million, or 3 cents per share, compared to \$0.7 million, or 3 cents per share, for the same period in 2011. The increase in net income was primarily due to improvement in net

operating losses at Gill Ranch, which had comparatively low storage revenues during the first quarter of 2011 because most of its capacity contracts did not begin until April 1, 2011. The Gill Ranch improvement was partially offset by lower revenues and net income from firm storage and asset management services at Mist. In total, gas storage margin increased \$1.4 million to \$6.7 million for the three months ended March 31, 2012.

Business Segments - Other

Our other business segment consists primarily of NNG Financial's investment in KB Pipeline, our equity investment in PGH, which in turn has invested in the Palomar pipeline project, and other miscellaneous non-utility investments and business activities. NNG Financial had total assets of \$1.0 million and \$1.1 million as of March 31, 2012 and 2011, respectively, primarily reflecting a non-controlling interest in KB Pipeline which is contracted to serve our utility. Our net equity investment in PGH as of March 31, 2012 and 2011 was \$13.5 million and \$14.8 million, respectively, with the decrease year-over-year reflecting a \$1.3 million write-down taken in 2011. In aggregate, earnings from our other business segment for the three months ended March 31, 2012 and 2011 were net income of \$10 thousand and a net loss of less than \$100 thousand respectively. See Note 4 and Note 12 in the 2011 Form 10-K, and Note 4 and Note 11 in this report, for further details on our other segment and our investment in PGH.

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Consolidated Operations

Operations and Maintenance

Consolidated operations and maintenance expense was \$34.4 million in 2012, compared to \$31.2 million in 2011, an increase of \$3.2 million or 10 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense for the three months ended March 31, 2012 compared to March 31, 2011:

- a \$1.1 million increase in utility payroll primarily related to an increase in field service employees;
- a \$1.5 million increase in utility non-payroll expense including higher costs for new employee training, the Oregon general rate case, IT systems maintenance and other customer service costs; and
- a \$0.9 million increase in utility employee benefit expense, principally related to health care and pension costs. See below for an additional discussion on pension costs.

Partially offsetting the factors above was:

- a \$0.3 million reduction in operating expense at Gill Ranch due to higher start-up costs for Gill Ranch in the first quarter of 2011.

Our bad debt expense as a percent of revenues was 0.23 percent for the twelve months ended March 31, 2012, compared to 0.18 percent for the same period last year. Our bad debt expense results over the past few years have been favorable despite challenging economic conditions. We believe credit risks are still elevated due to the continuing weak economy and high unemployment rates, but we expect our bad debt expense ratio over the long term to remain below 0.5 percent of revenues.

Our accounting expense for pension costs increased fairly significantly in 2012 largely due to lower interest rates; however, the OPUC approved the deferral of NW Natural's utility pension costs when its qualified defined benefit pension plans' operations and maintenance cost exceeds the amount currently recovered in rates. The pension cost deferral was recorded to a regulatory balancing account, which reduced operations and maintenance expense by \$2.1 million for the three months ended March 31, 2012 and \$1.3 million for the same period last year (see Note 8). Therefore, increased pension costs had a minimal effect on operations and maintenance expense, with the increase principally related to the cost allocation to our Washington customers. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—Pension Deferral," above.

General Taxes

General taxes increased \$0.7 million in the first three months of 2012 compared to 2011 primarily due to a \$0.5 increase in property taxes at Gill Ranch because of capital investments added to our California tax base in 2011.

Depreciation and Amortization

For the three months ended March 31, 2012, depreciation and amortization expense increased by \$0.6 million, or 4 percent compared to the same period in 2011. The increased expense in 2012 was related to higher depreciation at the utility and Gill Ranch because of plant asset additions.

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Other Income and Expense – Net

The following table provides details on other income and expense – net by primary components:

Thousands	Three Months Ended March 31,	
	2012	2011
Gains from company-owned life insurance	\$784	\$505
Interest income	16	7
Income (loss) from equity investments	(1)	-
Net interest on deferred regulatory accounts	1,005	1,514
Gain (loss) on sale of investments	-	(96)
Other non-operating	(799)	(716)
Total other income and expense - net	\$1,005	\$1,214

Other income and expense – net for the three months ended March 31, 2012 decreased \$0.2 million over 2011, with the decrease primarily due to lower interest from net regulatory asset account balances, partially offset by a \$0.3 million increase in gains from life insurance policy proceeds.

Interest Expense – Net

Interest expense – net increased by \$0.7 million for the three months ended March 31, 2012 compared to the first three months of 2011, with the increase primarily due to interest on Gill Ranch's new \$40 million debt balance that was issued in late 2011.

Income Tax Expense

The change in income tax expense was not material for the three months ended March 31, 2012, compared to the same period in 2011. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and our effective rates, see Note 9.

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Financial Condition

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting 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 of capital are also used to fund long-term debt redemptions and short-term commercial paper maturities (see “Liquidity and Capital Resources,” below, and Note 7). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at March 31, 2012 and 2011 and at December 31, 2011 was as follows:

	March 31,		December 31,	
	2012	2011	2011	
Common stock equity	49.7	% 47.9	% 46.5	%
Long-term debt	42.7	% 36.5	% 41.7	%
Short-term debt, including current maturities of long-term debt	7.6	% 15.6	% 11.8	%
Total	100	% 100	% 100	%

Liquidity and Capital Resources

At March 31, 2012, we had \$4.0 million of cash and cash equivalents compared to \$3.5 million at March 31, 2011. We also had \$4.0 million in restricted cash at Gill Ranch as of March 31, 2012, which is being held as collateral on the long-term debt outstanding. The \$0.9 million of restricted cash at Gill Ranch as of March 31, 2011 was held as collateral for equipment purchase contracts, but that amount was released back to Gill Ranch when contract conditions were met. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances, add short-term borrowing capacity, or pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC, and our use of proceeds from utility specific issuances are restricted to certain utility purposes. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, borrowings from multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use utility long-term debt proceeds to finance utility capital expenditures, refinance maturing debt of the utility and provide for general corporate purposes of the utility.

Capital markets over the past few years, including the commercial paper market, experienced significant volatility and tight credit conditions, but current conditions have improved significantly as reflected by tighter credit spreads and increased access to new financing for investment grade issuers. Based on our current debt ratings (see “Credit Ratings,” below), we have been able to issue commercial paper and first mortgage bonds at attractive rates and have not needed

to borrow from our back-up credit facilities. In the event that we are not able to issue new debt due to market conditions, we expect that our near term liquidity needs can be met by using cash balances or, for the utility segment, drawing upon our committed credit facilities. We also have a universal shelf registration filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of March 31, 2012, we have OPUC approval to issue up to \$125 million of additional debt under the existing shelf registration for approved purposes.

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In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional cash requirements and may trigger significant increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on March 31, 2012, we could have been required to post up to \$40.4 million of collateral to our counterparties, but that assumes our long-term debt ratings were downgraded to non-investment grade levels, which would be a very significant change from current rating levels for NW Natural (see Note 12 and “Credit Ratings,” below).

Additionally, in July 2010, the U.S. Congress passed and President Obama signed into law the “Wall Street Reform and Consumer Protection Act.” The legislation requires additional government regulation of derivative and over-the-counter transactions, and could expand collateral requirements. While we continue to evaluate the legislation to determine its impact, if any, on our hedging procedures, results of operations, financial position and liquidity, we do not expect to know the full impact of the legislation until final regulations implementing the legislation are issued.

Recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, tax benefits and liabilities, environmental expenditures and insurance recoveries, and refunds to customers. With respect to pension requirements, we expect to make significant contributions over the next several years until we are fully funded under the Pension Protection Act rules (see “Pension Cost and Funding Status of Qualified Retirement Plans,” below). With respect to federal income tax liabilities, an extension was granted that allowed us to take 100 percent bonus depreciation on qualified expenditures during 2011, and allows 50 percent bonus depreciation on a majority of our capital expenditures in 2012, which significantly reduces our tax liability for those tax years and provides cash flow benefits in 2012 and 2013 (see “Cash Flows—Operating Activities,” below). With respect to environmental liabilities, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance or utility rates over the next several years, although the amount and timing of these expenditures and recoveries is uncertain (see Note 13).

With respect to customer refunds or credits, our actual gas costs have been significantly lower in recent months than the gas prices embedded in customer rates. As a result, our PGA incentive sharing mechanism deferred 90 percent of these gas cost savings attributed to Oregon, and 100 percent of the savings attributed to Washington, into a regulatory account for refund back to customers (see “Purchased Gas Adjustment,” above). Ordinarily, these refunds would be credited to customer rates in the next year’s PGA filing, but in April 2012 the company requested regulatory approval to immediately credit an estimated \$35 million to Oregon customers and \$4 million to Washington customers through billing credits. In addition, in April 2012 the company also requested regulatory approval to provide its Oregon utility customers with an estimated \$9 million interstate storage credit from our regulatory incentive sharing mechanism related to gas storage and asset management services. If approved, we intend to apply both of these credits to customer bills in June of 2012.

Our storage segment’s short-term liquidity is supported by cash balances, internal cash flow from operations, external financing, and to a certain extent on funding from its parent company. Gill Ranch has a limited operational history, having begun operations in October 2010. Although we anticipate operating cash flows to be sufficient for liquidity purposes, the amount and timing of these cash flows are uncertain. In November 2011, Gill Ranch issued \$40 million of senior secured notes, with a fixed interest rate on \$20 million and a variable interest rate on the remaining \$20 million. The average combined interest rate on the notes was 7.38 percent per annum through March 31, 2012. These notes are secured by all of the membership interests in Gill Ranch Storage, LLC, and are nonrecourse to NW Natural and other entities of the consolidated group. The maturity date of these notes is November 30, 2016.

Under the note agreements, Gill Ranch is subject to certain covenants and restrictions, including but not limited to a financial covenant that requires Gill Ranch to maintain minimum adjusted EBITDA at various levels over the term of the notes. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the agreements, Gill Ranch is also subject to a debt service reserve requirement of 10 percent of the outstanding principal amount, initially \$4 million, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on incurrence of additional debt.

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Based on several factors, including our current credit ratings, our commercial paper program, current cash reserves, committed credit facilities, and our expected ability to issue long-term debt under our universal shelf registration, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations and investing and financing activities discussed below.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas inventories and accounts receivable, short-term debt may also be used to temporarily fund utility 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 one or more unsecured revolving credit facilities (see “Credit Agreements,” below). Our commercial paper program did not experience any liquidity disruptions as a result of the credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs over the last several years. At March 31, 2012 and 2011, our utility had commercial paper outstanding of \$113.7 million and \$186.4 million, respectively. The effective interest rate on the utility’s commercial paper outstanding at March 31, 2012 and 2011 was 0.2 percent and 0.4 percent, respectively.

Credit Agreements

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling \$250 million. The original term of this credit agreement was extended through May 31, 2013. All lenders under our syndicated agreement are major financial institutions with committed balances and investment grade credit ratings as of March 31, 2012 (see table below). This credit facility is scheduled to expire next year, and we plan to negotiate a replacement credit facility later this year.

Lender rating, by category	Loan Commitment (In Thousands) Syndicated Facility
AAA/Aaa	\$ -
AA/Aa	165,000
A/A	85,000
BBB/Baa	-
Total	\$ 250,000

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

As discussed above, we extended commitments with all of our lenders under the \$250 million syndicated agreement through May 31, 2013. This syndicated agreement allows us to request increases in the total commitment amount from time to time, up to a maximum amount of \$400 million. This syndicated agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment.

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Any principal and unpaid interest amounts owed on borrowings under the credit agreements are due and payable on or before the maturity date. There were no outstanding balances under these credit agreements at March 31, 2012 and 2011. These agreements require us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at March 31, 2012 and 2011, with consolidated indebtedness to total capitalization ratios of 50 percent and 52 percent, respectively.

The syndicated agreement also requires that we maintain credit ratings with S&P and Moody's and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings by S&P or by Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. However, a change in our debt rating below BBB- by S&P or Baa3 by Moody's would require additional approval from the OPUC prior to issuance of utility debt, and interest rates on any loans outstanding under the credit agreements are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreements when ratings are changed (see "Credit Ratings," below).

Credit Ratings

Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets, including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. A change in our ratings below BBB- by S&P or Baa3 by Moody's would require additional approval from the OPUC prior to our issuing additional long-term debt.

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

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-1
Senior secured (long-term debt)	A+	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

The above 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.

Maturities and Redemptions of Long-Term Debt

For the three months ended March 31, 2012, \$40 million of secured Medium Term Notes (MTNs) with a coupon rate of 7.13% were redeemed at maturity. Over the next twelve months, there are no scheduled redemptions of long-term debt. For long-term debt maturing over the next five years, see "Contractual Obligations" in our 2011 Form 10-K.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are affected by net income, working capital requirements, and other cash and non-cash adjustments to operating results. For the three months ended March 31, 2012, cash flows from operating activities totaled \$114.1 million, compared to \$108.1 million in 2011. The significant factors contributing to changes in operating cash flows in the first quarter of 2012 compared to 2011 are as follows:

- an increase of \$ 23.5 million from deferred gas cost savings, which reflects a higher level of refunds due utility customers for differences between actual gas prices and the embedded gas prices in amounts billed to customers;
- an increase of \$9.5 million from changes in customer receivables primarily due to higher account balances at the end of 2011 compared to 2010 because of colder weather at the end of 2011;

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- a decrease of \$14.2 million from changes in gas inventories primarily due to lower inventory withdrawals during the first quarter of 2012 as compared to 2011 because the utility was able to take advantage of lower spot gas prices to reduce cost of gas;
- a decrease of \$11.8 million from changes in income tax account balances primarily related to prior year income tax refunds received in the first quarter of 2011; and
- a decrease of \$11.6 million from changes in gas costs payable primarily due to weather and inventory withdrawal impacts on gas purchases between the two periods.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the Tax Relief Act) allowed 100 percent bonus depreciation on qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50 percent bonus depreciation deduction to qualifying property placed in service during 2012. As a result of this and prior legislation allowing bonus depreciation, we generated cash flow benefits of \$27.0 million and \$25.0 million for the three months ended March 31, 2012 and 2011, respectively. These and other tax benefits resulted in a net operating tax loss for 2010, which was carried back to the tax year 2009 and resulted in a federal income tax refund of \$22.3 million received in 2011. We also continue to recognize an increase in cash flows for reduced current tax liabilities due to net operating loss (NOL) carry-forwards. As of March 31, 2012, we had an income tax receivable balance of \$1.7 million, which we expect to realize during 2012, and an NOL carry-forward balance of \$57.0 million. We anticipate being able to use the full amount of the current NOL carry-forward balance in future years. The federal NOL from 2010 would expire in 2031 if not used in earlier years.

Also affecting cash flow from operating activities is the amount of cash contributions being made to the utility's qualified defined benefit pension plans (qualified DB plans). During the first quarter of 2012, we contributed \$13.8 million to the qualified DB plans, which was significantly higher than the \$2.0 million in non-cash expense recognized on the income statement, and for the first quarter of 2011, we contributed \$13.6 million while only \$1.8 million in non-cash expense was recognized on the income statement. We expect contributions to the qualified DB plans to exceed non-cash expense for the next few years, but amounts and timing of these expenses will depend on market interest rates and investment returns on the plans' assets.

Investing Activities

Cash used in investing activities for the three months ended March 31, 2012 totaled \$37.7 million, up from \$25.5 million for the same period in 2011. The increase in investing activities is primarily due to a \$17.2 million investment in utility gas reserves during the first quarter of 2012 (see "Executive Summary – Strategic Opportunities – Gas Reserves" above for a discussion of our gas reserve agreement with Encana). Utility capital expenditures were \$18.9 million and gas storage capital spend was \$1.5 million in the three months ended March 31, 2012, as compared to \$16.7 million and \$8.7 million, respectively, for the same period in 2011.

In the first quarter of 2012, we purchased a property in Sherwood, Oregon which, along with anticipated sale of existing properties, will enable us to consolidate certain operations at the new location. This will allow us to consolidate and streamline certain field operations and maintenance groups, plus provide us with expanded scenario-based pipeline training capabilities and a back-up business operations site.

Over the five-year period 2012 through 2016, total utility capital expenditures are estimated to be between \$400 and \$500 million and utility expenditures for gas reserves are estimated to be \$200 million. The estimated level of utility capital requirements over the next five years reflects assumptions on customer growth, storage development for the utility, technology investments and utility distribution system improvements, including requirements under current

pipeline safety programs. New federal pipeline safety rules could increase our capital requirement estimates over the next five years. Most of the funds required to make these investments over the next five years are expected to be internally generated, and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing.

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In 2012, we expect to spend less than \$5 million on non-utility capital projects, including the storage businesses and Palomar. Non-utility gas storage capital expenditures in 2012 are expected to be paid primarily from working capital, and potentially with additional funds from the NW Natural consolidated group. Palomar expects to continue working on revised plans for the east pipeline segment, including plans to conduct an open season to re-evaluate regional needs. The initial planning and permitting costs have been financed with equity funds from NW Natural and our partner, TransCanada American Investments Ltd. For more information on non-utility investment opportunities, see Note 11 and “Strategic Opportunities—Gas Storage Development” and “—Pipeline Diversification,” above.

Financing Activities

Cash used in financing activities during the three months ended March 31, 2012 totaled \$78.1 million, up from cash used of \$82.5 million for the same period in 2011. The primary change in financing activity in 2012 over 2011 was the amount used to redeem \$40 million of long-term debt in the first quarter of 2012, which reduced the amount of cash flow used to reduce the short-term debt balances outstanding from \$71 million in 2011 to \$27.9 million in 2012. We continue to use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt maturities, and for general corporate purposes. We anticipate issuing long-term debt later on during 2012.

Pension Cost and Funding Status of Qualified Retirement Plans

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans were underfunded by \$146.9 million at December 31, 2011. For the three months ended March 31, 2012, we made cash contributions totaling \$13.8 million into these qualified pension plans. We anticipate making additional contributions before year end, bringing the total amount to around \$28 million in 2012. In 2011 and 2010, we contributed \$20 million and \$10 million, respectively, into the qualified defined benefit pension plans. For more information on the funded status of our qualified retirement plans and other postretirement benefits, see Note 8, and Part II, Item 7., “Financial Condition—Pension Cost and Funding Status of Qualified Retirement Plans,” and Part II, Item 8., Note 9, “Pension and Other Postretirement Benefits,” in the 2011 Form 10-K.

We also contribute to a multi-employer union pension plan (Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling \$0.1 million to the Western States Plan in both the three months ended March 31, 2012 and 2011, and we expect to contribute a total of \$0.4 million during 2012. See Note 8 for further discussion.

Ratios of Earnings to Fixed Charges

For the three and twelve months ended March 31, 2012 and the twelve months ended December 31, 2011, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 6.81, 3.36 and 3.41 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. See Exhibit 12.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies (see Part II, Item 7., “Application of Critical Accounting Policies and Estimates,” in our 2011 Form 10-K). At March 31, 2012, we had a regulatory asset of \$112.3 million for deferred environmental costs, which includes \$75.1 million for additional costs expected to be paid in the future and accrued interest of \$20.4 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 13.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price and storage value risk, interest rate risk, foreign currency risk, credit risk, and weather risk. We monitor and manage these financial exposures as an integral part of our overall risk management program. No material changes have occurred related to our disclosures about market risk for the three months ended March 31, 2012. See Part I, Item 1A., "Risk Factors," and Part II, Item 7A. "Quantitative and Qualitative Disclosures about Market Risk," in the 2011 Form 10-K and Part II, Item 1A., "Risk Factors," in this report for details regarding these risks.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company's management, together with its consolidated subsidiaries, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 13 and those proceedings disclosed and incorporated by reference in Part I, Item 3., "Legal Proceedings," in our 2011 Form 10-K, we have only routine nonmaterial litigation in the ordinary course of business.

ITEM 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, "Item 1A. Risk Factors," in our 2011 Form 10-K. In addition to the other information set forth in this report, you should carefully consider those risk factors, which could materially affect our business, financial condition or results of operations.

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

The following table provides information about purchases by us during the quarter ended March 31, 2012 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASE OF EQUITY SECURITIES

Period	(a)	(b)	(c)	(d)
	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2)	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2)
Balance forward			2,124,528	\$ 16,732,648
01/01/12 - 01/31/12	-	\$-	-	-
02/01/12 - 02/29/12	1,062	47.66	-	-
03/01/12 - 03/31/12	7,888	46.14	-	-
Total	8,950	\$46.32	2,124,528	\$ 16,732,648

(1) During the quarter ended March 31, 2012, 8,950 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended March 31, 2012, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2012 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of \$100 million. During the quarter ended March 31, 2012, no shares of our common stock were purchased pursuant to this program. Since the program's inception in 2000 we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately \$83.3 million.

ITEM 6. EXHIBITS

See Exhibit Index attached hereto.

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SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)

Dated: May 4, 2012

/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 the Quarter Ended

March 31, 2012

Exhibit Number	Document
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	*The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.

* In accordance with Rule 406T of Regulation S-T, the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q is deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act, is deemed not filed for purposes of Section 18 of the Exchange Act and otherwise is not subject to liability under these sections.

