NORTHWEST NATURAL GAS CO
Form 10-Q
May 02, 2013

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

Form 10-Q

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

For the quarterly period ended March 31, 2013

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 number 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 [X] No [ ]

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 [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See 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 [X] 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 [X]

At April 26, 2013, 26,948,572 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, 2013

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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;
- timing and cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- gas reserves;
- operational performance and costs;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- project development and expansion;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate recovery and refunds;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- outcomes and effects of litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- availability, adequacy, 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 2012 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 INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended March 31,	
In thousands, except per share data	2013	2012
Operating revenues	$277,861	$309,639
Operating expenses:		
Cost of gas	142,359	169,755
Operations and maintenance	33,757	34,432
General taxes	8,732	8,836
Depreciation and amortization	18,807	17,950
Total operating expenses	203,655	230,973
Income from operations	74,206	78,666
Other income and expense, net	520	472
Interest expense, net	11,127	11,191
Income before income taxes	63,599	67,947
Income tax expense	25,960	27,663
Net income	37,639	40,284
Other comprehensive income:		
Amortization of non-qualified employee benefit plan liability, net of taxes of $151 for 2013 and $108 for 2012	233	166
Comprehensive income	$37,872	$40,450
Average common shares outstanding:		
Basic	26,929	26,781
Diluted	26,973	26,862
Earnings per share of common stock:		
Basic	$1.40	$1.50
Diluted	1.40	1.50
Dividends declared per share of common stock	0.455	0.445

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	March 31, 2013	March 31, 2012	December 31, 2012
Assets:			
Current assets:			
Cash and cash equivalents	$8,337	$4,031	$8,923
Accounts receivable	84,346	90,817	61,229
Accrued unbilled revenue	29,633	44,444	56,955
Allowance for uncollectible accounts	(2,116)	(3,694)	(2,518)
Regulatory assets	39,001	90,490	52,448
Derivative instruments	8,200	1,824	1,950
Inventories	52,004	61,436	67,602
Gas reserves	14,286	6,732	14,966
Income taxes receivable	2,033	1,735	2,552
Other current assets	12,441	13,075	19,592
Total current assets	248,165	310,890	283,699
Non-current assets:			
Property, plant, and equipment	2,808,673	2,680,537	2,786,008
Less: Accumulated depreciation	824,561	779,683	812,396
Total property, plant, and equipment, net	1,984,112	1,900,854	1,973,612
Gas reserves	100,169	61,106	84,693
Regulatory assets	384,453	364,132	382,255
Derivative instruments	2,836	52	3,639
Other investments	68,029	67,648	67,667
Restricted cash	4,000	4,000	4,000
Other non-current assets	14,735	14,191	13,555
Total non-current assets	2,558,334	2,411,983	2,529,421
Total assets	$2,806,499	$2,722,873	$2,813,120

See Notes to Consolidated Financial Statements.

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PART I. FINANCIAL INFORMATION

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	March 31, 2013	March 31, 2012	December 31, 2012
Liabilities and equity:			
Current liabilities:			
Short-term debt	$130,750	$113,700	$190,250
Accounts payable	77,007	60,165	85,613
Taxes accrued	10,262	10,509	9,588
Interest accrued	10,952	10,648	5,953
Regulatory liabilities	28,239	50,341	20,792
Derivative instruments	3,450	53,697	10,796
Other current liabilities	41,445	41,503	45,444
Total current liabilities	302,105	340,563	368,436
Long-term debt	691,700	641,700	691,700
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	467,360	436,750	444,377
Regulatory liabilities	293,135	288,131	288,113
Pension and other postretirement benefit liabilities	215,808	189,003	215,792
Derivative instruments	642	3,947	578
Other non-current liabilities	79,112	79,461	74,497
Total deferred credits and other non-current liabilities	1,056,057	997,292	1,023,357
Commitments and contingencies (see Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,948, 26,798, and 26,917 at March 31, 2013 and 2012 and December 31, 2012, respectively	357,957	351,005	356,571
Retained earnings	407,738	399,946	382,347
Accumulated other comprehensive loss	(9,058)	(7,633)	(9,291)
Total equity	756,637	743,318	729,627
Total liabilities and equity	$2,806,499	$2,722,873	$2,813,120

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

In thousands	Three Months Ended March 31, 2013	2012
Operating activities:		
Net income	$37,639	$40,284
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	18,807	17,950
Deferred tax liabilities	25,797	26,879
Non-cash expenses related to qualified defined benefit pension plans	1,476	2,007
Contributions to qualified defined benefit pension plans	(1,400)	(13,800)
Deferred environmental expenditures, net of recoveries	(4,482)	(827)
Other	1,836	476
Changes in assets and liabilities:		
Receivables	5,281	6,378
Inventories	15,598	12,927
Taxes accrued	1,193	5,072
Accounts payable	(13,781)	(26,050)
Interest accrued	4,999	4,791
Deferred gas costs	1,966	23,663
Other, net	11,189	14,304
Cash provided by operating activities	106,118	114,054
Investing activities:		
Capital expenditures	(22,674)	(20,447)
Utility gas reserves	(12,257)	(17,220)
Other	(1,335)	(68)
Cash used in investing activities	(36,266)	(37,735)
Financing activities:		
Common stock issued, net	1,115	1,458
Long-term debt retired	—	(40,000)
Change in short-term debt	(59,500)	(27,900)
Cash dividend payments on common stock	(12,248)	(11,913)
Other	195	234
Cash used in financing activities	(70,438)	(78,121)
Decrease in cash and cash equivalents	(586)	(1,802)
Cash and cash equivalents, beginning of period	8,923	5,833
Cash and cash equivalents, end of period	$8,337	$4,031
Supplemental disclosure of cash flow information:		
Interest paid	$6,128	$6,148
Income taxes paid	—	101

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
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 the 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), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and NW Natural Gas Reserves, LLC (NWN Gas Reserves). 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) and NNG Financial's investment in Kelso-Beaver (KB) Pipeline. 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.

During the first quarter of 2013, we identified an error in the rate used to calculate interest on regulatory assets. We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the interim period ending March 31, 2013, if corrected in 2013. As a result, in accordance with accounting standards, we have revised our prior period financial statements as shown in Note 14 to correct for this error.

Certain prior year balances in our consolidated financial statements and notes have been reclassified to conform with the current presentation. These changes had no impact on our prior year’s consolidated results of operations, financial condition or cash flows.

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 2012 Annual Report on Form 10-K (2012 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

Our significant accounting policies are described in Note 2 of the 2012 Form 10-K. There were no material changes to those accounting policies during the three months ended March 31, 2013. The following are current updates to certain critical accounting policy estimates and accounting standards in general.

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Regulatory Accounting

In applying regulatory accounting in accordance with generally accepted accounting principles in the United States of America (GAAP), we capitalize or defer certain costs and revenues as regulatory assets and liabilities. At March 31, 2013 and 2012 and at December 31, 2012, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	March 31,		December 31,
In thousands	2013	2012	2012
Current:			
Unrealized loss on derivatives(1)	$3,450	$53,697	$10,796
Pension and other postretirement benefit liabilities(2)	17,247	15,491	17,247
Other(3)	18,304	21,302	24,405
Total current	$39,001	$90,490	$52,448
Non-current:			
Unrealized loss on derivatives(1)	$642	$3,947	$578
Pension balancing(2)	17,322	8,367	14,727
Income tax asset	53,065	63,452	55,879
Pension and other postretirement benefit liabilities(2)	178,377	166,639	182,688
Environmental costs(4)	125,671	108,007	121,144
Other(3)	9,376	13,720	7,239
Total non-current	$384,453	$364,132	$382,255

	Regulatory Liabilities		
	March 31,		December 31,
In thousands	2013	2012	2012
Current:			
Gas costs	$8,694	$35,584	$9,100
Unrealized gain on derivatives(1)	8,054	1,824	1,950
Other(3)	11,491	12,933	9,742
Total current	$28,239	$50,341	$20,792
Non-current:			
Gas costs	$1,407	$14,462	$—
Unrealized gain on derivatives(1)	2,836	52	3,639
Accrued asset removal costs	285,437	270,837	281,213
Other(3)	3,455	2,780	3,261
Total non-current	$293,135	$288,131	$288,113

(1) Unrealized gains or losses on derivatives are non-cash items and therefore do 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 (PGA) mechanism when realized at settlement.

(2) Certain utility pension costs are approved for regulatory deferral, including amounts recorded to the pension balancing account, to mitigate the effects of higher and lower pension expenses. Pension costs that are deferred include an interest component when recognized in net periodic benefit costs. See Note 7.

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

(4) Environmental costs relate to specific sites approved for regulatory deferral by the Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC). In Oregon, we earn a carrying charge on amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. In the 2012 Oregon general rate case, the OPUC authorized a Site Remediation and Recovery Mechanism (SRRM)

that allows the Company to recover prudently incurred environmental costs, subject to an earnings test that will be defined in a rate proceeding that is currently underway. See Note 13.

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New Accounting Standards

Adopted Standards

BALANCE SHEET OFFSETTING. In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance regarding the offsetting of assets and liabilities on the balance sheet. The standard is intended to provide more comparable guidance between the 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 on or after January 1, 2013. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 12 for our full disclosure.

RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME. In February 2013, FASB issued authoritative guidance, which requires an entity to present significant amounts reclassified from each component of accumulated other comprehensive income (AOCI). This standard is intended to improve the reporting of these reclassifications by consolidating the information concerning amounts reclassified into net income from AOCI, which has been presented throughout the financial statements. This guidance is effective for reporting periods beginning after December 15, 2012. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 7 for our full disclosures.

Recent Accounting Pronouncements

There were no significant accounting standards issued during the first quarter of 2013.

Subsequent Events

There are no subsequent events to report for the period ended March 31, 2013.

3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted-average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted-average number of common shares outstanding plus the 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:

	Three Months Ended March 31,	
In thousands, except per share data	2013	2012
Net income	$37,639	$40,284
Average common shares outstanding - basic	26,929	26,781
Additional shares for stock-based compensation plans outstanding	44	81
Average common shares outstanding - diluted	26,973	26,862
Earnings per share of common stock - basic	$1.40	$1.50
Earnings per share of common stock - diluted	$1.40	$1.50
Additional information:		
Anti-dilutive shares excluded from net income per diluted common share calculation	32	1

4. SEGMENT INFORMATION

We operate in two primary reportable business segments, local gas distribution 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 refer to our local gas distribution business as the “utility,” and our “gas storage” and “other” business segments as “non-utility.” Our utility segment includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp and the utility portion of our Mist facility. 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 Mist underground storage facility in Oregon (Mist), and all third-party asset management services. Our “other” segment includes NNG Financial and NWN Energy's equity

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investment in PGH, which is pursuing development of a cross-Cascades pipeline project. See Note 4 in our 2012 Form 10-K for further discussion of our segments.

The following table presents summary financial information concerning the reportable segments. Inter-segment transactions are insignificant:

	Three Months Ended Three Months Ended March 31,			
In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$269,659	$8,146	$56	$277,861
Depreciation and amortization	17,188	1,619	—	18,807
Income from operations	70,228	3,957	21	74,206
Net income (loss)	36,031	1,636	(28)	37,639
Capital expenditures	22,388	286	—	22,674
Total assets at March 31, 2013	2,501,724	288,795	15,980	2,806,499
2012				
Operating revenues	$302,905	$6,679	$55	$309,639
Depreciation and amortization	16,338	1,612	—	17,950
Income from operations	75,964	2,679	23	78,666
Net income	39,468	806	10	40,284
Capital expenditures	19,656	791	—	20,447
Total assets at March 31, 2012	2,420,194	286,756	15,923	2,722,873
Total assets at December 31, 2012	2,505,655	291,568	15,897	2,813,120

Utility margin is a financial measure consisting of utility operating revenues less the associated cost of gas. By netting fluctuating costs of gas from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The following table presents additional segment information concerning utility margin. The gas storage and other segments emphasize growth in operating revenues and net income as opposed to margin because these segments do not incur cost of sales like the utility and, therefore, use operating revenues and net income to assess performance.

	Three Months Ended March 31,	
In thousands	2013	2012
Utility margin calculation:		
Utility operating revenues	$269,659	$302,905
Less: Utility cost of gas	142,359	169,755
Utility margin	$127,300	$133,150

5. STOCK-BASED COMPENSATION

Our stock-based compensation plans include a Long-Term Incentive Plan (LTIP) under which various types of equity awards may be granted, an Employee Stock Purchase Plan, and a Restated Stock Option Plan (Restated SOP). 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 2012 Form 10-K and updates provided below.

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Long-Term Incentive Plan

Performance-Based Stock Awards
LTIP performance shares incorporate market, performance, and service-based factors. On February 27, 2013, 37,300 performance-based shares were granted under the LTIP based on target-level awards and a weighted-average grant date fair value of $38.96 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	$45.38	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.455	
Expected dividend yield	3.9	%
Dividend discount factor	0.8943	

Performance-Based Restricted Stock Units (RSUs)
On February 27, 2013, 25,748 performance-based RSUs were granted under the LTIP with a grant date fair value of $45.38 per share. The RSUs awarded 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 that portion of the RSU.

Restated Stock Option Plan
As of March 31, 2013, there was $0.4 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. The Restated SOP was terminated for new option grants in 2012; however, options that had been granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP. No stock options were granted in the three months ended March 31, 2013.

6. DEBT

Short-Term Debt
At March 31, 2013, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 254 days, an average maturity of 61 days, and an outstanding balance of $130.8 million. The carrying cost of our commercial paper approximates fair value using Level 2 inputs due to the short-term nature of the notes. See Note 2 in our 2012 Form 10-K for a description of the fair value hierarchy.

Long-Term Debt
At March 31, 2013, our utility's long-term debt consisted of $651.7 million of first mortgage bonds (FMBs) with maturity dates ranging from 2014 through 2042, interest rates ranging from 3.176% to 9.05%, and a weighted-average coupon rate of 5.71%. During the three months ended March 31, 2012, we did not issue or redeem any FMBs.

At March 31, 2013, our gas storage segment’s long-term debt consisted of $40 million of senior secured debt with a maturity date of November 30, 2016. This debt consists of $20 million of fixed rate debt with an interest rate of 7.75% and $20 million of variable interest rate debt, which currently has an interest rate of 7.00%. The debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural.

As our outstanding debt does not trade in active markets, we estimate the fair value of our outstanding long-term debt using interest rates of other companies’ outstanding debt issuances that actively trade in public markets and have similar credit ratings, terms, and remaining maturities to our debt. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2 in our 2012 Form 10-K.

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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:

	March 31,		December 31,
In thousands	2013	2012	2012
Carrying amount	$691,700	$641,700	$691,700
Estimated fair value	825,038	742,852	834,664

See Note 7 in our 2012 Form 10-K for more detail on our long-term debt.

7. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

The following table provides the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans:

	Three Months Ended Three Months Ended March 31,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2013	2012	2013	2012
Service cost	$2,341	$2,130	$179	$177
Interest cost	4,103	4,304	286	314
Expected return on plan assets	(4,678)	(4,638)	—	—
Amortization of net actuarial loss	4,421	3,843	169	103
Amortization of prior service costs	56	49	49	49
Amortization of transition obligations	—	—	—	103
Net periodic benefit cost	6,243	5,688	683	746
Amount allocated to construction	(1,855)	(1,418)	(219)	(214)
Amount deferred to regulatory balancing account[1]	(2,349)	(2,068)	—	—
Net amount charged to expense	$2,039	$2,202	$464	$532

[1] Effective January 1, 2011, the 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 net periodic benefit costs in future years. Deferred pension expense balances accrue interest at the utility's actual cost of long-term debt. See Note 2.

The following table presents amounts recognized in accumulated other comprehensive loss (AOCL) and the changes in AOCL related to our non-qualified employee benefit plan:

In thousands	
Beginning balance at December 31, 2012	$(9,291)
Amounts reclassified into AOCL	—
Amounts reclassified from AOCL:	
Amortization of prior service costs	(2)
Amortization of actuarial gains (losses)	386
Total reclassifications before tax	384
Tax expense	(151)
Total reclassifications for the period	233
Ending balance at March 31, 2013	$(9,058)

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Employer Contributions to Company-Sponsored Defined Benefit Pension Plan

In the three months ended March 31, 2013, we made cash contributions totaling $1.4 million to our qualified defined benefit pension plan. In 2012, Congress passed the "Moving Ahead for Progress in the 21st Century Act" (MAP-21), which among other things, includes provisions that reduce the level of minimum required contributions in the near-term but generally increase contributions in the long-run as well as increase the operational costs of running a pension plan. Including the impacts of MAP-21, we expect to make approximately $10 million in additional pension contributions during 2013.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit pension plan referred to above, we contribute to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan) in accordance with our collective bargaining agreement. The employer identification number of the plan is 94-6076144. The cost of this plan, and corresponding future liabilities, are in addition to pension expense presented in the table above. Our contributions to the Western States Plan amounted to $0.1 million for the three months ended March 31, 2013 and 2012. Under the terms of our current collective bargaining agreement, we can withdraw from the Western States Plan at any time. However, if the plan is underfunded at the time we withdraw, we would be assessed a withdrawal liability. In accordance with accounting rules for multiemployer plans, we have not recognized these potential withdrawal liabilities on the balance sheet. Currently, we have made no decision to withdraw from the plan. We continue to monitor the financial condition of the plan and consider options with respect thereto.

Defined Contribution Plan

The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Our contributions to this plan totaled $0.5 million and $0.7 million for the three months ended March 31, 2013 and 2012, respectively.

See Note 8 in the 2012 Form 10-K for more information about these retirement and other postretirement benefit plans.

8. INCOME TAX

The effective income tax rate for the three months ended March 31, 2013 and 2012 varied from the combined federal and state statutory tax rates principally due to the following:

	March 31,			
	2013		2012	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.7		4.6	
Amortization of investment and energy tax credits	(0.3	)	(0.3	)
Differences required to be flowed-through by regulatory commissions	2.4		1.6	
Gains on company and trust-owned life insurance	(0.3	)	(0.4	)
Other, net	(0.7	)	0.2	
Effective income tax rate	40.8	%	40.7	%

See Note 9 in the 2012 Form 10-K for more detail on income taxes and effective tax rates.

9. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and related accumulated depreciation at March 31, 2013 and 2012 and December 31, 2012:

	March 31,		December 31,
In thousands	2013	2012	2012
Utility plant in service	$2,452,419	$2,342,681	$2,435,886
Utility construction work in progress	53,474	34,903	46,831
Less: Accumulated depreciation	799,864	760,566	789,201
Utility plant, net	1,706,029	1,617,018	1,693,516
Non-utility plant in service	296,228	297,164	296,781
Non-utility construction work in progress	6,552	5,789	6,510
Less: Accumulated depreciation	24,697	19,117	23,195
Non-utility plant, net	278,083	283,836	280,096
Total property, plant, and equipment	$1,984,112	$1,900,854	$1,973,612

10. GAS RESERVES

Our utility gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet.

We entered into agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop physical gas reserves. These agreements are intended to provide long-term gas price protection for our utility customers rather than serving as a source of gas supply. Encana began drilling in 2011 under these agreements, and gas which is currently being produced from our working interests in these gas fields is sold by Encana at then prevailing market prices, with revenues from such sales, net of associated production costs, credited to our cost of gas. The cost of gas, including a carrying cost for the net rate base investment, is part of our annual Oregon PGA filing, which allows us to recover our costs through customer rates in a manner previously approved by the OPUC. This transaction acted to hedge the cost of gas for approximately 3% of our gas supplies for the three months ended March 31, 2013. The following table outlines our net investment at March 31, 2013 and 2012 and December 31, 2012:

	March 31,		December 31,
In thousands	2013	2012	2012
Gas reserves, current	$14,286	$6,732	$14,966
Gas reserves, non-current	110,033	63,546	92,179
Less: Accumulated amortization	9,864	2,440	7,486
Total gas reserves	114,455	67,838	99,659
Less: Deferred taxes on gas reserves	32,907	22,047	28,329
Net investment in gas reserves	$81,548	$45,791	$71,330

11. INVESTMENTS

Equity Method Investments

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% by NWN Energy and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Variable Interest Entity (VIE) Analysis

PGH is a development stage VIE. As of March 31, 2013, there were no changes to our VIE analysis and, as such, we continue to report Palomar under equity method accounting based on the determination 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% share and there are no stipulations that allow disproportionate influence over the entity. Our investment in PGH and Palomar are included in other investments on our balance sheet. Our maximum

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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% owner.

Impairment Analysis
Our investments in nonconsolidated entities accounted for under the equity method 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 PGH was $13.4 million at March 31, 2013. PGH is continuing to work on development of commercial support for the project. A new Federal Energy Regulatory Commission (FERC) certificate application is expected to be filed to reflect a revised scope based on regional needs for the proposed pipeline. If we learn that the project is not viable or will not go forward in the future, 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 PGH. We will continue to monitor and update our impairment analysis as required. See Note 12 in our 2012 Form 10-K for more detail.

Other Investments
Other investments include financial investments in life insurance policies, which are accounted for at fair value. See Note 12 in the 2012 Form 10-K for more detail on other investments.

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 price variability 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 utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to these physical gas supply contracts. The following table presents the absolute notional amounts related to open positions on financial derivative instruments:

	March 31,		December 31,
Dollars in thousands	2013	2012	2012
Open position absolute notional amount:			
Natural gas (millions of therms)	30.2	32.8	39.5
Foreign exchange	$16,322	$12,954	$13,231

Derivatives entered into prudently by the utility 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 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10% or 20% recognized in current income. All of our commodity hedging for the 2012-13 gas year was completed prior to the start of the gas year, and these hedge prices were included in the Company's 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, 2013 and 2012. Our outstanding derivative instruments are primarily related to regulated utility operations as illustrated by the unrealized derivative gains and losses being deferred in accordance with regulatory accounting standards. We also enter into exchange contracts related to the optimization of our gas portfolio, which may qualify as derivatives but do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement.

	Three Months Ended			
	March 31, 2013		March 31, 2012	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Cost of sales	$7,183	$—	$(55,894)	$—
Other comprehensive income (loss)	—	(239)	—	126
Less:				
Amounts deferred to regulatory accounts	(7,037)	239	55,894	(126)
Total gain in pre-tax earnings	$146	$—	$—	$—

No collateral was posted with or by our counterparties as of March 31, 2013 or 2012. 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 portfolio diversification, we have not been subject to collateral calls in 2012 or 2013. 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 $0.2 million at March 31, 2013, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$—	$—	$—	$—	$8,290
Without Adequate Assurance Calls	—	—	—	—	5,516

Our derivative financial instruments are subject to master netting arrangements; however, they are presented on a gross basis on the face of our statement of financial position. If netted by counterparty, our derivative position would result in an asset of $8.3 million and a liability of $1.4 million as of March 31, 2013.

In the three months ended March 31, 2013 and 2012, we realized net losses of $5.4 million and $29.4 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

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 customers. See Note 13 in our 2012 Form 10-K for more information on our derivative instruments.

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, 2013. As of March 31, 2013 and 2012 and December 31, 2012, the fair value was an

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asset of $6.9 million, and a liability of $55.8 million, and a liability of $5.8 million, respectively, using significant other observable, or Level 2, inputs. We have used no Level 3 inputs in our derivative valuations. We did not have any transfers between Level 1 or Level 2 during the three months ended March 31, 2013 and 2012.

13. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation 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. 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 possible loss and the fact that the high end of the range cannot be reasonably estimated. 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 low 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 our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives.

Environmental site remediation costs are deferred under regulatory approval from the OPUC and WUTC. In addition, the OPUC authorized a mechanism (SRRM) that allows the Company to recover prudently incurred environmental site remediation costs, subject to an earnings test that will be defined in a current proceeding. Actual cost recovery under SRRM will depend upon future insurance recoveries, future expenditures, annual prudence reviews, and the impacts of any earnings test the OPUC may adopt in our currently open docket. Cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such determination is made.

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). 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.

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other non-current liabilities on the balance sheet:

	Current Liabilities			Non-Current Liabilities		
	March 31,		December 31,	March 31,		December 31,
In thousands	2013	2012	2012	2013	2012	2012
Portland Harbor site:						
Gasco/Siltronic Sediments	$389	$2,459	$2,207	$38,050	$43,655	$36,087
Other Portland Harbor	1,678	1,400	1,767	2,793	3,547	3,160
Gasco Uplands site	15,411	13,197	18,722	8,365	7,689	5,028
Siltronic Uplands site	556	478	637	414	588	379
Central Service Center site	80	—	140	386	424	396
Front Street site	760	1,131	993	199	395	—

Oregon Steel Mills	—	—	—	179	116	185
Total	$18,874	$18,665	$24,466	$50,386	$56,414	$45,235

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The following table presents information regarding the total amount of cash paid for environmental sites and the total regulatory asset deferred:

	March 31,		December 31,
In thousands	2013	2012	2012
Cash paid	$75,620	$58,989	$71,124
Total regulatory asset deferral(1)	125,671	108,007	121,144

(1) Total regulatory asset deferral includes cash paid, remaining liability, interest, and insurance reimbursement.

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 11 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands and Siltronic uplands sites. We have been notified that we are a potentially responsible party to the Superfund site and we have joined with other potentially responsible parties (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). The LWG submitted a draft Feasibility Study (FS) to EPA in March 2012 that 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 will select for the entire Portland Harbor Superfund site. The cost 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. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

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 uplands and Siltronic uplands sites. NW Natural submitted 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. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA range from $38.4 million to $350 million. 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 $4.4 million for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG which is performing the RI/FS for EPA. NW Natural may also incur 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. We have accrued a liability for these claims which is at the low end of the range of the potential liability. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

GASCO UPLANDS SITE. NW Natural owns a former gas manufacturing plant that was closed in 1956 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality (ODEQ) Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and submitted it to ODEQ for review. We have recognized a liability for this portion of the site remediation which is at the low end of the range of potential liability.

In 2012, ODEQ approved our final design remediation plan for a groundwater source control system on which we began construction in October 2012. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding the effectiveness of the source control system, we have estimated a range of liability between $14.5 million and $25 million, for which we have recorded an accrued liability

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which is at the low end of the range of the potential liability. We are uncertain about the range due to potential additional ODEQ requirements and actions needed to meet those requirements, including uncertainty about how to meet the agreed standards set by ODEQ subsequent to the initial testing of the system and as part of the final remedy for the uplands portion of the Gasco site.

OTHER SITES. In addition to those sites above, we have environmental exposures at four other sites, Siltronic, Central Service Center, Front Street, and Oregon Steel Mills. Due to the uncertainty of the design of remediation, regulation, timing of the liabilities, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites has been recognized at their respective low end of the range of potential liability and the high end of the range cannot be reasonably estimated. See "Legal Proceedings" below.

Legal Proceedings

NW Natural is 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, NW Natural does 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. See also Part II, Item 1, "Legal Proceedings."

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.

14. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

During the first quarter of 2013, we identified an error in the rate used to calculate interest on certain regulatory assets. Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if the regulator provides orders that create probable recovery of past costs through future revenues. We have accrued interest as specified by regulatory order on certain regulatory balances at our authorized rate of return (ROR). This ROR includes both a debt and equity component, which we are allowed to recover from customers in the form of a carrying cost on regulatory deferred account balances. As the equity component of our ROR is not an incurred cost that would otherwise be charged to expense, this portion of the carrying cost should not have been capitalized for financial reporting purposes.

We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the interim period ending March 31, 2013, if corrected in 2013. As a result, in accordance with accounting standards, we have revised our prior period financial statements as described below to correct for this error. The revision had no effect on reported cash flows.

The adjustment impacted years 2003 through 2012 with a cumulative pre-tax decrease over that period of $5.6 million to regulatory assets and other income and expense. The revision decreased net income by $1.1 million, $0.9 million and $0.7 million for the years ended December 31, 2012, 2011 and 2010, respectively. The cumulative decrease to

January 1, 2010 retained earnings was $0.7 million as a result of the revision.

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The following table presents the income statement effects related to this revision for the years ended December 31:

	2012			2011			2010		
In thousands, except per share data	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance
Other income and expense, net	$4,936	$(1,777)	$3,159	$4,523	$(1,411)	$3,112	$7,102	$(1,083)	$6,019
Income before income taxes	103,959	(1,777)	102,182	107,280	(1,411)	105,869	122,129	(1,083)	121,046
Income tax expense	44,104	(701)	43,403	43,382	(557)	42,825	49,462	(429)	49,033
Net Income	59,855	(1,076)	58,779	63,898	(854)	63,044	72,667	(654)	72,013
Comprehensive income	58,364	(1,076)	57,288	62,702	(854)	61,848	72,031	(654)	71,377
Basic EPS	2.23	(0.04)	2.19	2.39	(0.03)	2.36	2.73	(0.02)	2.71
Diluted EPS	2.22	(0.04)	2.18	2.39	(0.03)	2.36	2.73	(0.03)	2.70

The following table presents the balance sheet effects of this revision as of December 31:

	2012			2011		
In thousands	Reported Balance	Adjustment	Adjusted Balance	Reported Balance	Adjustment	Adjusted Balance
Non-current assets:						
Regulatory assets	$387,888	$(5,633)	$382,255	$371,392	$(3,856)	$367,536
Total non-current assets	2,535,054	(5,633)	2,529,421	2,397,885	(3,856)	2,394,029
Total assets	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718
Liabilities and equity:						
Deferred credits and other non-current liabilities:						
Deferred tax liabilities	$446,604	$(2,227)	$444,377	$413,209	$(1,526)	$411,683
Total deferred credits and other non-current liabilities	1,025,584	(2,227)	1,023,357	975,922	(1,526)	974,396
Equity:						
Retained earnings	385,753	(3,406)	382,347	373,905	(2,330)	371,575
Total equity	733,033	(3,406)	729,627	714,488	(2,330)	712,158
Total liabilities and equity	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718

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The following tables present the income statement and balance sheet corrections for the following quarters:

	2012							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,005	$472	$921	$620	$1,710	$1,180	$1,300	$887
Income (loss) before income taxes	68,480	67,947	2,296	1,995	(13,594)	(14,124)	46,777	46,364
Income tax expense (benefit)	27,873	27,663	887	768	(3,036)	(3,245)	18,380	18,217
Net income (loss)	40,607	40,284	1,409	1,227	(10,558)	(10,879)	28,397	28,147
Comprehensive income (loss)	40,773	40,450	1,575	1,393	(10,391)	(10,712)	26,407	26,157
Basic EPS	1.52	1.50	0.05	0.05	(0.39)	(0.41)	1.06	1.05
Diluted EPS	1.51	1.50	0.05	0.05	(0.39)	(0.41)	1.05	1.04
Non-current assets:								
Regulatory assets	$368,521	$364,132	$366,981	$362,290	$367,692	$362,472	$387,888	$382,255
Total non-current assets	2,416,372	2,411,983	2,448,359	2,443,668	2,492,467	2,487,247	2,535,054	2,529,421
Total assets	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$438,486	$436,750	$440,073	$438,217	$430,885	$428,821	$446,604	$444,377
Total deferred credits and other non-current liabilities	999,028	997,292	991,007	989,151	985,729	983,665	1,025,584	1,023,357
Equity:								
Retained earnings	402,599	399,946	392,082	389,247	369,584	366,428	385,753	382,347
Total equity	745,971	743,318	737,570	734,735	717,559	714,403	733,033	729,627
Total liabilities and equity	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120

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	2011							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,214	$1,291	$1,122	$779	$1,781	$1,426	$406	$(384)
Income (loss) before income taxes	68,627	68,704	3,509	3,166	(14,012)	(14,367)	49,156	48,366
Income tax expense (benefit)	27,854	27,884	1,316	1,181	(5,700)	(5,840)	19,912	19,600
Net income (loss)	40,773	40,820	2,193	1,985	(8,312)	(8,527)	29,244	28,766
Comprehensive income (loss)	40,919	40,966	2,339	2,131	(8,166)	(8,381)	27,610	27,132
Basic EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.08
Diluted EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.07
Non-current assets:								
Regulatory assets	$345,452	$343,085	$326,081	$323,371	$328,757	$325,692	$371,392	$367,536
Total non-current assets	2,290,848	2,288,481	2,294,100	2,291,390	2,317,293	2,314,228	2,397,885	2,394,029
Total assets	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$396,357	$395,419	$398,825	$397,751	$394,217	$393,003	$413,209	$411,683
Total deferred credits and other non-current liabilities	873,714	872,776	874,842	873,768	866,927	865,713	975,922	974,396
Equity:								
Retained earnings	385,899	384,470	376,489	374,853	356,574	354,723	373,905	371,575
Total equity	723,228	721,799	714,628	712,992	696,605	694,754	714,488	712,158
Total liabilities and equity	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718

	Six months ended June 30, 2012		Nine months ended September 30, 2012	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,926	$1,092	$3,636	$2,272
Income before income taxes	70,776	69,942	57,182	55,818
Income tax expense	28,760	28,431	25,724	25,186
Net Income	42,016	41,511	31,458	30,632
Comprehensive income	42,348	41,843	31,957	31,131
Basic EPS	1.57	1.55	1.17	1.14
Diluted EPS	1.56	1.54	1.17	1.14

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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 or the Company) 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, 2013 and 2012. 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 these three month periods are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2012 Annual Report on Form 10-K (2012 Form 10-K).

The consolidated financial statements include NW Natural, the parent company, and its direct and indirect wholly-owned subsidiaries, which include and are organized as follows:

We operate in two primary reportable business segments, local gas distribution 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 refer to our local gas distribution business as the “utility,” and our “gas storage” and “other” business segments as “non-utility.” In addition, our statements also include 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), and NNG Financial's investment in KB Pipeline. For a further discussion of 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, which is a non-GAAP financial measure. These amounts reflect factors that directly impact earnings. In calculating these financial disclosures, we allocate income tax expense based on the effective tax rate, where applicable. All references in this section to earnings per share (EPS) are on the basis of diluted shares (see Part II, Item 8., Note 3, “Earnings Per Share,” in our 2012 Form 10-K). We use such non-GAAP measures in analyzing our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

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EXECUTIVE SUMMARY

Key financial highlights include:

	Three Months Ended March 31,		
In thousands, except per share data	2013	2012	Change
Consolidated net income	$37,639	$40,284	$(2,645)
Consolidated EPS	1.40	1.50	(0.10)
Utility margin	127,300	133,150	(5,850)

Results for the first quarter 2013 compared to the first quarter of 2012 include:

- a decrease in consolidated net income and EPS primarily due to lower utility margin, partially offset by lower utility operations and maintenance expenses, and higher net income from gas storage operations;
- a decrease in utility margin primarily related to the revenue timing impacts in this first year following the 2012 Oregon General Rate Case. In addition, lower gains from gas cost savings decreased utility margin due to larger decreases in actual gas prices compared to Purchased Gas Adjustment (PGA) rates in 2012 versus 2013; and
- increases in utility margin from customer growth and the rate-base return on our gas reserve investments.

In addition to our financial results for the first quarter of 2013, we also continue to make progress on several key initiatives including:

- customer growth opportunities through regulatory and legislative efforts for natural gas in the vehicle transportation market, as well as marketing efforts in our traditional customer groups;
- planning work on the next gas storage expansion at our Mist facility; and
- resolving regulatory dockets that remained open from the 2012 Oregon general rate case.

Our progress on, and commitment to, these initiatives are a part of our core business objectives and long-term strategic plan. See Part II, Item 7, “2013 Outlook” in our 2012 Form 10-K and "Strategic Opportunities" below.

Issues, Challenges and Performance Measures

ECONOMY. The local, national, and global economies showed some signs of growth during the first quarter of 2013. Our utility’s annual customer growth rate was 1.1% at March 31, 2013, compared to 0.8% at March 31, 2012. The unemployment rates in our region have declined to approximately 8% from over 11% in 2009, and new housing permits in Oregon have increased. We will continue to monitor the economy, but believe our utility business is well positioned to continue adding customers and to serve increasing energy demand as the economy recovers because of low, stable natural gas prices, our relatively low market penetration, and our ongoing focus on converting homes and businesses to natural gas. In addition, environmental initiatives that favor lower carbon emissions and lower cost energy alternatives such as natural gas could increase demand for our services in the future.

GAS PRICES AND SUPPLIES. Our gas acquisition strategy is to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so we can effectively manage costs, reduce price volatility, and maintain a competitive advantage. With recent developments in drilling technologies and substantial access to supplies around the U.S. and in Canada, the current outlook for North American natural gas supply is strong and is projected to remain this way well into the future. The continuation of low and stable gas prices in the future depends on a combination of supply outlook and demand factors as well as a regulatory environment that continues to support hydraulic fracturing and other drilling technologies.

Our utility’s annual PGA mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and secure low, stable gas costs for our customers. See "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" below.

We typically hedge gas prices for approximately 75% of our utility's annual sales requirement based on average weather, including both physical and financial hedges. We entered the 2012-13 gas year (November 1, 2012 – October 31, 2013) hedged at 75% of our forecasted sales volumes, including 47% in financial swaps and option contracts and 28% in physical gas supplies. The physical hedges consisted of a combination of gas inventories in

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storage, local production from the Mist area, and supply region production from utility gas reserve investments. For further discussion of gas reserves, see “Strategic Opportunities—Gas Reserves” below.

In addition to the amount hedged for the current gas contract year, we are also hedged at approximately 25% for the 2013-14 gas year and between 8% and 23% 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. Also, our storage inventory levels may increase or decrease based on storage expansion, storage contracts with third parties, or storage recall by the utility.

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 storage contracts with customers at favorable prices affects our financial results. However, if there is an increase in demand for natural gas or a decrease in drilling activity, there may be upward pressure on gas prices or an increase in gas price volatility, which may result in increased demand or prices for storage services. In the short-term, we strive to find opportunities for increasing revenues, lowering costs, and developing enhanced services for storage customers.

ENVIRONMENTAL COSTS. We accrue all environmental 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 actions. In our most recent general rate case, the Public Utility Commission of Oregon (OPUC) approved the recovery of costs from environmental site remediation subject to certain conditions as noted in "Results of Operations—Regulatory Matters—Rate Mechanisms" below.

We are pursuing recovery from insurance policies through litigation and only seek recovery from customers for amounts not covered by insurance. Ultimate recovery of environmental costs from regulated utility rates will depend on our ability to effectively manage these costs, demonstrate that costs were prudently incurred, and the impact of any earnings test the OPUC adopts as a result of a currently open proceeding. Environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding. Based on these proceedings, 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 Note 13 in this report and Note 15 in our 2012 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 strategies for:

- growing our utility services and operations;
- exploring new service opportunities in the natural gas industry;
- optimizing and growing our non-utility gas storage businesses;
- investing in natural gas infrastructure as needed to support the energy needs of our region; and
- maintaining a leadership role in the gas utility industry by advancing long-term energy policies.

See Part II, Item 7, “Issues, Challenges, and Performance Measures” in our 2012 Form 10-K for a discussion of our performance metrics.

Strategic Opportunities

SAFETY, RELIABILITY, AND SERVICE. We are continually committed to customer and employee safety, operational effectiveness, service quality, and leveraging our competitive position. We have several ongoing initiatives designed to improve the quality, effectiveness, and integrity of our utility and non-utility business operations, and we have upgraded several facilities to enhance business continuity, employee training, safety, productivity, and energy efficiency. In particular, our initiatives in 2013 will further enhance our commitment to safety. For example, the Company has increased staffing levels in the areas of pipeline safety, emergency response, regulatory compliance, field training, and customer service to respond to new federal pipeline safety legislation and system integrity requirements as well as customer expectations for service responsiveness.

GAS STORAGE. We own and operate two underground gas storage facilities—the Mist facility in Oregon and the Gill Ranch facility near Fresno, California. Storage operations benefit from seasonal swings in commodity pricing and market volatility. Our storage facilities position us to capitalize on rising demand for natural gas, higher gas prices, or increased market volatility. Currently natural gas prices remain relatively low and stable; however, if there is an increase in demand for natural gas, a decrease in drilling activity, or other factors, including weather, there may be upward pressure on gas prices or price volatility may return. We have the ability to expand both facilities beyond their current capacities.

The Pacific Northwest storage market has also been impacted by lower gas prices and lack of gas price volatility, although less than in California due to greater seasonal price differentials. In addition, new flexible gas-fired generation is needed in the region to integrate intermittent wind resources into the power system, thereby increasing the associated need for gas storage. As a result, we are at the beginning stage of a new expansion at Mist. This expansion is anchored by an agreement to provide gas storage services to PGE for gas-fired generation facilities at Port Westward, Oregon. Our Mist expansion project is subject to several conditions, including NW Natural receiving regulatory approval. This expansion will likely include the development of new storage wells, a compressor station, and additional pipeline facilities that would enable more storage expansions in the future. Our goal is to have the additional storage capacity in service during 2016.

In addition, we currently estimate that the Gill Ranch storage facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 6.25 Bcf or ownership of a total of approximately 22.5 Bcf. An expansion at the Gill Ranch storage facility would require certain infrastructure investments, but no further expansion of our gas transmission pipeline.

PIPELINE DIVERSIFICATION. Currently, our utility operations and gas storage operations at Mist depend on a single bi-directional interstate transmission pipeline to ship gas supplies to customers. We continue to work with regulators and utilities in the Pacific Northwest to advance a new integrated, regional cross-Cascades pipeline through our Palomar investment to reduce this risk and create diversity and increased reliability for our system.

The proposed pipeline would be regulated by the Federal Energy Regulatory Commission (FERC). Palomar intends to file an application with FERC for a pipeline delivering gas from the GTN pipeline near Madras in central Oregon to a NW Natural hub near Molalla, Oregon. The application will be filed after NW Natural has completed resource plans and Palomar has conducted a new open season to obtain adequate commercial support for the pipeline. The approval and timing of potential construction of the pipeline will depend on the project being competitive with alternative Pacific Northwest pipeline projects, obtaining regulatory permits, and garnering the necessary commercial support from shippers. See Note 11 for further discussion.

GAS RESERVES. In addition to hedging gas prices with financial derivative contracts, we entered into an agreement with Encana Oil & Gas (USA) Inc. (Encana) in 2011 to hedge a portion of our Oregon utility customers' cost of gas over an estimated 30 years. We have invested in working interests in certain gas leases. These working interests are in a gas field located in Sublette County, Wyoming. During the first 10 years of the contract, we forecast the volumes of gas to be produced under the gas reserves agreement as sufficient to hedge approximately 8% to 10% of the average annual utility gas supply requirements. We receive certain federal tax deductions for drilling costs incurred under our gas reserves agreements. The timing of when we realize these federal tax benefits has been affected by net operating losses (NOLs) for tax purposes, which will be carried forward to reduce our current tax liability in future years. We continue to evaluate additional investments in gas reserves as part of our gas hedging strategy. See Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves" in our 2012 Form 10-K.

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CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings
Consolidated highlights include:

	Three Months Ended March 31,		
In thousands, except per share data	2013	2012	Change
Consolidated operating revenues	$277,861	$309,639	$(31,778)
Consolidated operating expenses	203,655	230,973	(27,318)
Consolidated interest expense, net	11,127	11,191	(64)
Consolidated net income	37,639	40,284	(2,645)
Consolidated EPS	1.40	1.50	(0.10)

2013 COMPARED TO 2012. The primary factors contributing to decreased first quarter consolidated net income were:

- a $5.9 million decrease in utility margin primarily due to:
  - a decrease in utility margin related to the revenue timing impact of changes in fixed monthly charges and the decoupling baseline in rates from our 2012 Oregon general rate case;
  - the overall revenue reduction tied partly to the lower authorized return on equity also from our rate case mentioned above; and
  - lower contribution to margin from our gas cost incentive sharing mechanism.

  Partially offsetting these decreases were margin increases from customer growth and our gas reserves investment.
- a $0.9 million increase in depreciation and amortization expenses primarily due to a higher level of investment in utility property, plant and equipment.

Partially offsetting the above factors were:

- a $1.5 million increase in gas storage operating revenues primarily due to revenue increases from additional contracted storage capacity at Gill Ranch for the 2012-2013 gas storage year;
- a $0.7 million decrease in utility operations and maintenance expense due to a decrease in our allowance for uncollectible accounts; and
- a $1.7 million decrease in income tax expense due to lower pre-tax income.

Dividends
Dividend highlights include:

	Three Months Ended March 31,		
Per common share	2013	2012	Change
Dividends paid	$0.455	$0.445	$0.01

The Board of Directors declared a quarterly dividend on our common stock of 45.5 cents per share, payable on May 15, 2013, to shareholders of record on April 30, 2013, reflecting an indicated annual dividend rate of $1.82 per share.

RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation with respect to, among other matters, rates, terms of service, and systems of accounts set by the OPUC, Washington Utilities and Transportation Commission (WUTC), and FERC. The OPUC and WUTC also regulate the issuance of securities by our utility. In 2012, approximately 90% of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 10% from Washington customers. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other regulatory proceedings 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. See "General Rate Cases" below.

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 intrastate and interstate storage services, respectively, under a maximum cost of service model which allows for storage prices to be set at or below the cost of service as approved by each agency in the last regulatory filing. 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 2012, approximately 54% of our storage revenues were derived from FERC and Oregon regulated operations and approximately 46% from California operations.

See Part II, Item 7, “Results of Operations—Regulatory Matters,” in the 2012 Form 10-K.

General Rate Cases

OREGON. Our most recent general rate case in Oregon was completed in 2012; the OPUC authorized rates to customers based on an ROE of 9.5% and an overall rate of return of 7.78% with a capital structure of 50% common equity and 50% long-term debt. These customer rates went into effect on November 1, 2012.

The following items were deferred for decision by the Commission to separate dockets:

- Prepaid Pension Assets - the Company requested to include prepaid pension assets in rate base and allow a return on and recovery of the asset; a new docket was ordered by the OPUC to review the treatment of pensions on a general, non-utility-specific basis. That docket is currently open. Until a conclusion is reached, the OPUC has authorized us to continue to collect and defer pension costs based on previous rate case recovery amounts;
- Interstate Storage Sharing - the existing arrangement we use to share revenues with customers from our Mist interstate storage operations and optimization services was continued, but a docket is to be opened to review the sharing arrangement;
- Working Gas Inventory - the OPUC ordered a review to determine the appropriate amount of working gas inventory that we earn a return on, and its corresponding rate of return. Included in the general rate decrease effective November 1, 2012 was a reduction in margin of about $4 million related to working gas inventory. We have been authorized to defer the carrying cost on working gas inventory pending the outcome of this open docket. The decision on this new docket will be applied retroactively to November 1, 2012; and
- Site Remediation and Recovery Mechanism (SRRM) - the earnings test for our new SRRM is also being developed in a separate, open proceeding; a prudence review for all past deferred environmental expenditures is also being conducted in this proceeding this year. Under the mechanism, an annual review for prudency of subsequent spend will be conducted each year. See "Environmental Costs" below.

We expect decisions on these open dockets during 2013 or 2014.

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. This includes gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, the application of temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80% deferral or a 90% 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% or 10% of the difference between actual and estimated gas costs, respectively. For the 2012-2013 PGA year, we selected the 90% deferral option. Under the Washington PGA mechanism, we defer 100% 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.

In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80% deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. We do not expect to be subject to a refund for the 2012 or 2013 earnings test years.

SYSTEM INTEGRITY PROGRAM (SIP). The OPUC has approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program and the related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and provided a two-year extension of our capital expenditure tracking mechanism to recover capital costs related to SIP. We record the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with these costs, subject to audit, through rate changes effective with the Oregon annual PGA. As such, our SIP costs are tracked into rates with the annual PGA filing, except that the first $3.3 million of capital costs, and an annual cap on expenditures of $12 million, are not included in the amounts tracked into rates annually. However, in April 2013 we signed a stipulation, which upon Commission approval, will increase the $3.3 million exclusion to $4 million while also increasing the $12 million annual cap by a total of $13.7 million over the next two tracker years. With the increased cap, we plan to be substantially complete with our bare steel replacement by the end of 2015, and as a result this stipulation precludes us from tracking any additional SIP costs into rates specifically for bare steel replacement after 2015.

ENVIRONMENTAL COSTS. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue a carrying cost on amounts deferred, 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 2012. In January 2013, we filed a request with the OPUC to continue our deferral of these environmental costs, and we are awaiting an order from the OPUC.

The new SRRM, authorized in the 2012 Oregon general rate case, allows the Company to recover prudently incurred environmental site remediation costs, net of insurance recoveries. This SRRM will allow recovery of one-fifth of the Company's currently deferred environmental expenses and future expenses as incurred each year in rates on a rolling basis until all such expenses are recovered, subject to an annual prudence review. Recovery of these incurred costs will also be subject to an earnings test, which has not yet been defined, but a docket has been opened on the matter. This earnings test could include deadbands, or other limitations based on our earnings in a year, which could reduce the amounts we are allowed to recover.

The WUTC has also authorized the deferral of environmental costs that are appropriately charged to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding. A decision regarding allocation of costs to each state is pending. See Note 13 for further discussion of our regulatory and insurance recovery of environmental costs.

PENSION DEFERRAL. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts 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 actual cost of

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long-term debt. The deferral from operations and maintenance expense in 2012 was $7.9 million. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and our pension contributions. We estimate pension expense deferrals totaling $8 million to $9 million in 2013, with $2.3 million being deferred for the three months ended March 31, 2013.

As noted above, the Company continues to seek rate treatment in Oregon for amounts invested in prepaid pension assets in a docket which is currently open. The timing of a decision on this docket is uncertain and may continue into 2014.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. In April 2013, the Company requested regulatory approval to provide its Oregon utility customers with an $8.8 million interstate storage credit, in their June bills, from our regulatory incentive sharing mechanism related to interstate gas storage and asset management services. Last year, the OPUC approved a $9.2 million credit, which was returned to Oregon customer in their June 2012 bills.

For a discussion of other rate mechanisms, see Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2012 Form 10-K.

Business Segments - Local Gas Distribution "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 utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff (also called the decoupling mechanism), which adjusts utility margin up or down each month through a deferred accounting adjustment 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 utility 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. See "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2012 Form 10-K for more information on our decoupling and weather normalization mechanisms.

Utility segment highlights include:

	Three Months Ended March 31,		
In thousands, except per share data	2013	2012	Change
Utility net income	$36,031	$39,468	$(3,437)
EPS - utility segment	$1.34	$1.47	$(0.13)
Gas sold and delivered (in therms)	400,190	408,159	(7,969)
Utility margin[1]	$127,300	$133,150	$(5,850)

[1] See Utility Margin Table below for additional detail.

2013 COMPARED TO 2012. The primary factors contributing to the decrease in net income were as follows:

- a $5.9 million decrease in utility margin primarily due to:
  - a $5.1 million decrease in margin related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 rate case. As a result of changes to the decoupling baseline for average use per customer included in the 2012 Oregon general rate case, the decoupling mechanism's results this year will not be comparable to last year, although the overall impact on revenues will generally be the same on an annualized basis;
  - a $0.7 million decrease in margin related to the general rate decrease primarily due to our lower authorized ROE of 9.5%;
  - a $2.1 million decrease in gains from gas cost incentive sharing; and
  - the effects of warmer weather, which decreased volumes and thus sales.

Partially offsetting these decreases was approximately $2 million increase related to customer growth and the rate-base return on our gas reserve investments.

- a $2.1 million decrease in income taxes due to lower pre-tax utility income.

Total utility volumes sold and delivered in the three months ended March 31, 2013 decreased 2% over last year primarily due to the impact of warmer weather on residential and commercial use.

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UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes and revenues and costs of sales for the three months ended March 31, 2013 and 2012. Certain prior year amounts in the following table have been reclassified to conform with the current year's presentation. These reclassifications reflect amounts included in residential, commercial, and industrial categories where such amounts were specifically attributable to that customer category. Utility volumes and margin in total were not affected by these reclassifications.

In thousands, except degree day and customer data	Three Months Ended Three Months Ended Three Months Ended March 31, 2013	 2012	Favorable/ (Unfavorable) 2013 vs. 2012
Utility volumes - therms:			
Residential and commercial sales	268,664	276,159	(7,495)
Industrial sales and transportation	131,526	132,000	(474)
Total utility volumes sold and delivered	400,190	408,159	(7,969)
Utility operating revenues:			
Residential and commercial sales	$256,366	$287,014	$(30,648)
Industrial sales and transportation	19,025	22,311	(3,286)
Other revenues	1,529	1,435	94
Less: Revenue taxes	7,261	7,855	(594)
Total utility operating revenues	269,659	302,905	(33,246)
Less: Cost of gas	142,359	169,755	(27,396)
Utility margin	$127,300	$133,150	$(5,850)
Utility margin:[1]			
Residential and commercial sales	$117,363	$121,415	$(4,052)
Industrial sales and transportation	7,718	7,636	82
Miscellaneous revenues	1,529	1,595	(66)
Gain from gas cost incentive sharing	542	2,637	(2,095)
Other margin adjustments	148	(133)	281
Utility margin	$127,300	$133,150	$(5,850)
Customers - end of period:			
Residential customers	623,609	617,665	5,944
Commercial customers	64,649	63,210	1,439
Industrial customers	941	919	22
Total number of customers - end of period	689,199	681,794	7,405
Actual degree days	1,904	1,954	
Percent colder (warmer) than average weather[2]	3%	4%	

(1) Amounts reported as margin for each category of customers are operating revenues, which are net of revenue taxes, less cost of gas.

(2) Average weather represents the 25-year average degree days, as determined in our Oregon general rate case. For the three months ended March 31, 2013 and 2012, average weather represents degree days based on the 25-year average that was set in our 2012 and 2003 Oregon general rate cases, respectively.

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Residential and Commercial Sales

Residential and commercial sales highlights include:

	Three Months Ended March 31,		
In thousands	2013	2012	Change
Volumes - therms:			
Residential sales	169,950	176,037	(6,087)
Commercial sales	98,714	100,122	(1,408)
Total volumes	268,664	276,159	(7,495)
Operating revenues:			
Residential sales	$172,168	$194,839	$(22,671)
Commercial sales	84,198	92,175	(7,977)
Total operating revenues	$256,366	$287,014	$(30,648)
Utility margin:			
Residential:			
Sales	$84,601	$85,608	$(1,007)
Weather normalization adjustments	(3,660)	(2,812)	(848)
Decoupling adjustments	2,817	6,201	(3,384)
Total residential utility margin	83,758	88,997	(5,239)
Commercial:			
Sales	33,647	32,965	682
Weather normalization adjustments	(1,638)	(1,003)	(635)
Decoupling adjustments	1,596	456	1,140
Total commercial utility margin	33,605	32,418	1,187
Total utility margin	$117,363	$121,415	$(4,052)

2013 COMPARED TO 2012. The primary factors contributing to changes in residential and commercial margin were as follows:

- sales volumes decreased 3%, primarily reflecting 3% warmer weather;
- operating revenues decreased 11%, due to a 3% decrease in sales volumes, a 14% decrease in average gas prices, which flowed through the Company's PGA rates; and
- utility margin decreased 3%, primarily reflecting:

a $5.1 million decrease due to timing differences of $2.8 million from the new fixed monthly charges and $2.4 million from the reset of decoupling baseline for average gas used by utility customers in Oregon; and

a $0.7 million decrease due to the overall revenue requirement decrease from the 2012 Oregon rate case, which included a decrease in our authorized ROE;

In addition, margin declined due to the effects of warmer weather.

Partially offsetting these decreases were increases of approximately $2.0 million from customer growth and the rate-base return on our gas reserve investments.

As a result of changes to the decoupling baseline for average use per customer included in the 2012 Oregon general rate case, the decoupling mechanism's results this year will not be comparable to last year, although the overall impact on revenues will generally be the same on an annualized basis.

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Industrial Sales and Transportation

Industrial sales and transportation highlights include:

	Three Months Ended March 31,		
In thousands	2013	2012	Change
Volumes - therms:			
Industrial - firm sales	9,480	10,619	(1,139)
Industrial - firm transportation	39,753	38,851	902
Industrial - interruptible sales	17,069	17,730	(661)
Industrial - interruptible transportation	65,224	64,800	424
Total volumes	131,526	132,000	(474)
Utility margin:			
Industrial - firm and interruptible sales	$3,684	$3,730	$(46)
Industrial - firm and interruptible transportation	4,034	3,905	129
Total utility margin	$7,718	$7,635	$83

2013 COMPARED TO 2012. The primary factors contributing to changes in industrial sales and transportation margin were as follows:

- total volumes decreased by less than 1% due to lower usage from a few large customers; and
- utility margin increased 1% due to customer growth of 2.4%, partially offset by decreased margins from the few large customers mentioned above.

Cost of Gas

Cost of gas 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 actual cost 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 in the PGA. In addition, we have a regulatory agreement where we earn a rate base return on our investment in gas reserves, which is reflected in utility margin. See “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above.

We use natural gas commodity hedge contracts (derivative instruments), 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 and normally do not impact net income because the hedged prices are reflected in our annual PGA rates, subject to a regulatory prudence review. However, hedge contracts entered into after the annual PGA rates are set for Oregon customers 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% 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 “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” in our 2012 Form 10-K, and Note 12 in this report.

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Cost of gas highlights include:

	Three Months Ended March 31,		
In thousands, except as noted	2013	2012	Change
Total volumes sold and delivered (therms)	400,190	408,159	(7,969)
Cost of gas	$142,359	$169,755	$(27,396)
Average cost of gas (cents per therm)	0.48	0.56	(0.08)
Total realized financial hedge losses on financial swaps	5,400	29,400	(24,000)
Utility margin gain from gas cost incentive sharing	542	2,637	(2,095)

2013 COMPARED TO 2012. The primary factors contributing to the 16% decrease in cost of gas were as follows:

- a 2% decrease in total sales volumes;
- average cost of gas collected through rates decreased 14%, primarily reflecting lower market prices for natural gas, which are passed on to customers through PGA rate changes on November 1 each year; and
- hedge losses realized and included in cost of gas decreased $24.0 million. Since underlying hedge prices are generally included in our PGA billing rates, hedge losses do not impact margin or net income.

The effect on shareholders from our gas cost incentive sharing mechanism was a contribution to margin of $0.5 million for the three months ended March 31, 2013, compared to $2.6 million for the same period in 2012. 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 75% ownership interest in the Gill Ranch underground storage facility in California. We also contract with an independent energy marketing company to provide asset management services using our utility and non-utility storage and transportation capacity.

Gas storage segment highlights include:

	Three Months Ended March 31,		
In thousands, except per share data and as otherwise noted	2013	2012	Change
Gas storage net income	$1,636	$806	$830
EPS - gas storage segment	0.06	0.03	0.03
Gas storage contracted capacity (Bcf)	21	19	2

2013 COMPARED TO 2012. The primary factor contributing to the increase in our gas storage segment was increased revenues at Gill Ranch from additional contracted storage capacity for the 2012-2013 gas storage year and higher third party asset management revenues. For the 2013-2014 gas storage year, we are fully contracted at Gill Ranch and at Mist, but market pricing for storage, particularly in California, has been negatively affected by the abundant supply of natural gas and low volatility of natural gas prices.

Business Segments - Other

Our other business segment primarily consists of an equity investment in KB Pipeline, an equity investment in PGH, which in turn has invested in a cross-Cascade pipeline project, and other miscellaneous non-utility investments and business activities.

Other business highlights include:

	Three Months Ended March 31,		
In thousands	2013	2012	Change
Investment in:			

NNG Financial	$1,150	$1,054	$96
PGH Investment	13,430	13,455	(25)

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2013 COMPARED TO 2012. Our other businesses remained relatively flat over the three months ended March 31, 2013 compared to the same period in 2012 with a net loss of less than $0.1 million in 2013 and net income of less than $0.1 million in 2012. See Note 4 and Note 11 for further details on our other business segment and our investment in PGH.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

	Three Months Ended March 31,		
In thousands	2013	2012	Change
Operations and maintenance	$33,757	$34,432	$(675)

2013 COMPARED TO 2012. The decrease in operations and maintenance expense was primarily due to a $1.3 million decrease in utility bad debt expense. Partially offsetting this decrease was a $0.5 million increase in utility employee related expense, principally related to health care and pension costs, which were driven by an increase in employee count. See below for further discussion on bad debt expense and pension costs below.

The utility's bad debt expense remains well below 0.5% of operating revenues and has decreased compared to 2012. This decrease is primarily due to lower levels of delinquent account balances during the period and a continuation of lower delinquency rates resulting in an overall decrease to our allowance for uncollectible accounts. Our bad debt expense results are at historically low levels for the Company despite challenging economic conditions in recent years.

Our accounting expense for pension costs increased in 2013 largely due to lower interest rates; however, we have OPUC approval to defer certain utility pension costs in excess of what is currently recovered in customer rates. The pension cost deferral is recorded to a regulatory balancing account, which stabilizes the recognized amount of operations and maintenance expense. For the three months ended March 31, 2013 and 2012, we deferred pension expenses totaling $2.3 million and $2.1 million, respectively. See Note 7. As a result, increased pension costs had a minimal effect on operations and maintenance expense in the current periods, with the increase principally related to the cost allocation to our Washington operations, and increases in our non-qualified and other postretirement benefit expenses, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see “Regulatory Matters—Rate Mechanisms—Pension Deferral,” above.

Income Tax Expense

Income tax expense highlights include:

	Three Months Ended March 31,		
Dollars in thousands	2013	2012	Change
Income tax expense	$25,960	$27,663	$(1,703)
Effective tax rate	40.8%	40.7%	0.1%

2013 COMPARED TO 2012. Income tax expense decreased in the first quarter of 2013 due to a $4.3 million decrease in income before income taxes compared to the same period in 2012. See Note 8 for more information on income taxes, including a reconciliation between the statutory federal and state income tax rates and our effective rates.

Other Consolidated Expenses

General taxes, depreciation and amortization, other income and expense, and interest expense were all relatively unchanged for the three months ended March 31, 2013 compared to the same period in 2012.

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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% common stock equity and 50% to 55% 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 retirements and short-term commercial paper maturities. See “Liquidity and Capital Resources” below and Note 6.

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 was as follows:

	March 31,				December 31,	
	2013		2012		2012	
Common stock equity	47.9	%	49.6	%	45.3	%
Long-term debt	43.8		42.8		42.9	
Short-term debt, including any current maturities of long-term debt	8.3		7.6		11.8	
Total	100	%	100	%	100	%

Liquidity and Capital Resources

At March 31, 2013, we had $8.3 million of cash and cash equivalents compared to $4.0 million at March 31, 2012. We also had $4.0 million in restricted cash at Gill Ranch at both March 31, 2013 and 2012, which is being held as collateral for its long-term debt outstanding. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances and add short-term borrowing capacity. In addition, we may also 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.

Current market conditions are better than the past few years as reflected by tighter credit spreads and increased access to financing for investment grade issuers. Based on our current debt ratings (see “Credit Ratings” below), we have been able to issue commercial paper and long-term debt at attractive rates and have not needed to borrow from our back-up credit facility. 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 facility. 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, 2013, we had OPUC approval to issue up to $75 million of additional long-term debt under the existing shelf registration for approved purposes.

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 increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on March 31, 2013, we could have been required to post $8.3 million of collateral to our counterparties, assuming our long-term debt ratings were at 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.

In July 2010, the U.S. Congress passed and President Obama signed into law the “Dodd-Frank Wall Street Reform and Consumer Protection Act” (Dodd-Frank Act or DFA). The legislation established a new statutory framework for

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the comprehensive regulation of financial institutions that participate in the swaps market and, among other things, requires additional government regulation of derivative and over-the-counter transactions and expanded collateral requirements. The Company is not currently subject to regulation as a Swap Dealer under the DFA nor do we expect that it will be in the future based on current or as yet unfinalized rules. Further, we believe we are eligible for and have taken appropriate steps to be exempt from certain reporting obligations under the DFA. We will continue to monitor interpretations and Commodity Futures Trading Commission guidance to determine the impact, if any, on our hedging policies, procedures, results of operations, financial position and liquidity.

Other recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, current tax benefits from bonus depreciation and other tax advantaged investments, environmental expenditures and insurance recoveries, and customer refunds of gas cost savings.

With respect to pensions, we expect to make significant contributions to our company-sponsored defined benefit plan, which is closed to new employees, over the next several years until we are fully funded under the Pension Protection Act rules, including the new rules issued under the MAP-21 Act. See Part II, Item 7, "Application of Critical Accounting Policies—Accounting for Pensions and Postretirement Benefits" in our 2012 Form 10-K.

Regarding federal income tax liabilities, extensions have been granted allowing us to take 50% bonus depreciation on a majority of our capital expenditures in 2012 and 2013 plus intangible drilling cost deductions from our gas reserves investment expected in 2011 - 2015, which significantly reduces our tax liability for those tax years and is expected to provide cash flow benefits in subsequent years.

Concerning environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance and utility rates over the next several years, although the amount and timing of these expenditures and recoveries is uncertain. See Note 13 and "Results of Operations—Regulatory Matters—Environmental Costs" above.

With respect to customer refunds or credits, in April 2013, the Company requested regulatory approval to provide its Oregon utility customers with an approximately $9 million interstate storage credit, in their June bills, from our regulatory incentive sharing mechanism related to interstate gas storage and asset management services. In 2012, the Company received approval to provide its Oregon utility customers with a $9 million interstate storage credit from the incentive sharing mechanism related to gas storage and asset management services, plus a $39 million refund to customers for gas cost savings. The 2012 credits were applied to customer bills in June and July of 2012.

Our gas storage segment’s short-term liquidity is supported by cash balances, internal cash flow from operations, external financing, and, to a certain extent, funding from its parent company. Gill Ranch has limited operational history, having begun operations in October 2010. We anticipate operating cash flows to be sufficient for liquidity purposes, but the amount and timing of these cash flows from year to year are uncertain as the majority of Gill Ranch's storage contracts are short-term. In November 2011, Gill Ranch issued $40 million of senior secured debt, 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 debt was 7.38% per annum through March 31, 2013. This debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural and other entities of the consolidated group. The maturity date of the debt is November 30, 2016.

Under the debt 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 earnings before interest, taxes, depreciation, and amortization (EBITDA) at various levels over the term of the debt. 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% of the outstanding principal amount, currently $4 million, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on the incurrence of additional debt. At March 31, 2013, we were in compliance with all covenants and restrictions under the debt agreements.

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 in the capital markets, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing and financing activities discussed below.

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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 purchases 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. At March 31, 2013 and 2012, our utility had commercial paper outstanding of $130.8 million and $113.7 million, respectively. The effective interest rate on the utility’s commercial paper outstanding at March 31, 2013 and 2012 was 0.3% and 0.2%, respectively.

Credit Agreements

In December 2012, we entered into a new multi-year credit agreement for unsecured revolving loans totaling $300 million with a maturity date of December 20, 2017 and an available extension of commitments for two additional one-year periods, subject to lender approval. All lenders under the new agreement are major financial institutions with committed balances and investment grade credit ratings as of March 31, 2013 as follows:

In thousands	
Lender rating, by category	Loan Commitment
AA/Aa	$123,000
A/A1	177,000
BBB/Baa	—
Total	$300,000

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.

Our credit agreement allows us to request increases in the total commitment amount, up to a maximum of $450 million. The agreement also permits the issuance of letters of credit in an aggregate amount of up to $200 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreements is due and payable on or before the maturity date. There were no outstanding balances under this or our prior credit agreement at March 31, 2013 or 2012. Both the current and former credit agreement requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% 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, 2013 and 2012, with consolidated indebtedness to total capitalization ratios of 52.1% and 50.4%, respectively.

The agreement also requires us to maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody’s) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings by S&P or 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. In addition, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore a change in the debt rating 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. In February 2013, S&P upgraded our secured long-term first mortgage bond rating from A+ to AA-. This change has not materially impacted our liquidity, access to the short-term commercial paper markets, or our borrowing costs. There were no other changes in our credit ratings during 2013.

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

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-2
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Negative

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.

Maturity and Redemption of Long-Term Debt
For the three months ended March 31, 2013, there were no redemptions or maturities of long-term debt, and there are no scheduled maturities or redemptions of long-term debt over the next twelve months. See Part II, Item 7, "Financial Condition—Contractual Obligations” in our 2012 Form 10-K for long-term debt maturing over the next five years.

Cash Flows

Operating Activities
Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements, and other cash and non-cash adjustments to operating results.

Operating activity highlights include:

	Three Months Ended March 31,		
In thousands	2013	2012	Change
Cash provided by operating activities	$106,118	$114,054	$(7,936)

2013 COMPARED TO 2012. The significant factors contributing to the decrease in operating cash flow for first quarter were as follows:

- a decrease of $21.7 million from changes in the deferred gas cost savings balance, due to large accumulated gas cost savings in 2012;
- a decrease of $3.9 million from changes in taxes accrued; and
- an increase of $3.7 million in deferred environmental expenditures due to higher payments related to environmental activities in 2013.

Partially offsetting these decreases was:

- a decrease of $12.4 million in contributions to qualified defined benefit pension plans primarily reflecting lower contribution requirements under "Moving Ahead for Progress in the 21st Century Act" (MAP-21), which among other things includes provisions that reduce the level of minimum required contributions in the near-term, but generally increases contributions in the long-run in addition to increasing the operational costs of running a pension plan; and
- an increase of $12.3 million from changes in accounts payable due a smaller reduction in gas costs in the first quarter of 2013 compared to 2012.

During the three months ended March 31, 2013, we contributed $1.4 million to our utility's qualified defined benefit pension plans, which was slightly lower than the $1.5 million in non-cash expense recognized on the income statement, compared to contributions of $13.8 million and $2.0 million in non-cash expense for the same three month period in 2012. We expect pension contributions to exceed non-cash expense for the next few years, but contribution amounts will be less than previously anticipated due to funding relief approved under the new MAP-21 Act in July

2012. The amounts and timing of future contributions will depend on market interest rates and investment returns on the plans' assets.

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Also significantly affecting cash flows over the past few years has been income tax legislation, including the American Taxpayer Relief Act of 2012 (2012 Act), which extended 50% bonus depreciation through 2013 for MACRS property with a recovery period of 20 years or less. 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 and an additional $2.1 million received in 2012. We generated taxable income in 2011 that was fully offset by an NOL carried forward from 2010. We continued to generate NOL carry-forwards during 2012. We estimate generating taxable income during 2013. As of March 31, 2013, we had an estimated federal income tax receivable balance of $2.0 million and an estimated NOL carry-forward balance of $76.6 million. In 2011 and 2012, Oregon conformed with federal bonus depreciation, contributing to a state NOL carryforward of $82.0 million. We anticipate being able to use the full amount of both NOL carryforward balances in future years prior to expiration. The NOLs would otherwise expire in 20 years for federal and 15 years for Oregon.

Investing Activities

Investing activity highlights include:

	Three Months Ended March 31,		
In thousands	2013	2012	Change
Total cash used in investing activities	$36,266	$37,735	$(1,469)
Capital expenditures	22,674	20,447	2,227
Utility gas reserves	12,257	17,220	(4,963)

2013 COMPARED TO 2012. The $1.5 million decrease in cash used in investing activities was due to the timing of payments for utility gas reserves partially offset by an increase in utility capital expenditures reflecting increased investment for new customer acquisitions and general system maintenance. For more information on capital projects, see “Cash Flows—Investing Activities” in the 2012 Form 10-K, and for more information on utility and non-utility investment opportunities, see Note 9 and “Strategic Opportunities,” above.

Financing Activities

Financing activity highlights include:

	Three Months Ended March 31,		
In thousands	2013	2012	Change
Total cash used in financing activities	$70,438	$78,121	$(7,683)
Change in short-term debt	59,500	27,900	31,600
Long-term debt retired	—	40,000	(40,000)
Cash dividend payments	12,248	11,913	335

2013 COMPARED TO 2012. The decrease in cash used in financing activity was primarily due to changes in our short-term debt balances, which increased $59.5 million in the first quarter of 2013 compared to an increase of $27.9 million in 2012. In addition, we also retired $40 million of long-term debt in the first quarter of 2012. We continue to use long-term debt proceeds to finance utility capital expenditures, refinance maturing short-term or long-term debt maturities, and to fund other general corporate purposes.

Ratios of Earnings to Fixed Charges

For the three and twelve months ended March 31, 2013 and the twelve months ended December 31, 2012, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission (SEC) method, were 6.47, 3.17, and 3.26, 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. The prior period amounts have been corrected for the prior period error identified during the period, see Note 14 for detail on the prior period correction and Exhibit 12 for the detailed ratio calculation.

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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 2012 Form 10-K. At March 31, 2013, we had a regulatory asset of $125.7 million for deferred environmental costs, which includes $69.3 million for additional costs expected to be paid in the future and $18.7 million of capitalized accrued interest. 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 and "Results of Operations—Rate Mechanisms—Environmental Costs" above.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements using 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 2012 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 2012 Form 10-K).

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.

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 month period ending March 31, 2013. See Part I and Part II, Item 1A, “Risk Factors” in this report and Part II, Item 7A, “Quantitative and Qualitative Disclosures about Market Risk” in the 2012 Form 10-K for details regarding these risks.

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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, 2013 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 2012 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 2012 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 of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended March 31, 2013:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (2)
Balance forward			2,124,528	$ 16,732,648
01/01/13 - 01/31/13	—	$—	—	—
02/01/13 - 02/28/13	1,183	45.72	—	—
03/01/13 - 03/31/13	3,944	43.72	—	—
Total	5,127	$44.18	2,124,528	$ 16,732,648

(1) During the quarter ended March 31, 2013, 5,127 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, 2013, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated SOP.
(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, 2013 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, 2013, 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 2, 2013

/s/ Brody J. Wilson
Brody J. Wilson
Principal Accounting Officer
Acting Controller

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Quarterly Report on Form 10-Q
For the Quarter Ended March 31, 2013

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, 2013, 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.