NORTHWEST NATURAL GAS CO
Form 10-Q
August 07, 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 June 30, 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	93-0256722
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (503) 226-4211

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

Indicate by check mark whether the registrant 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 [ ] (Do not check if a Smaller Reporting Company)	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 July 26, 2013, 26,975,108 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended June 30, 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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ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2013	2012	2013	2012
Operating revenues	$131,714	$103,991	$409,575	$413,630
Operating expenses:				
Cost of gas	59,142	34,498	201,501	204,253
Operations and maintenance	33,217	32,138	66,974	66,570
General taxes	7,342	7,417	16,074	16,253
Depreciation and amortization	18,930	18,099	37,737	36,049
Total operating expenses	118,631	92,152	322,286	323,125
Income from operations	13,083	11,839	87,289	90,505
Other income and expense, net	1,450	620	1,970	1,092
Interest expense, net	11,069	10,464	22,196	21,655
Income before income taxes	3,464	1,995	67,063	69,942
Income tax expense	1,338	768	27,298	28,431
Net income	2,126	1,227	39,765	41,511
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $151 and $109 for the three months and $302 and $217 for the six months ended June 30, 2013 and 2012, respectively	232	166	465	332
Comprehensive income	$2,358	$1,393	$40,230	$41,843
Average common shares outstanding:				
Basic	26,958	26,812	26,943	26,797
Diluted	26,999	26,896	26,991	26,879
Earnings per share of common stock:				
Basic	$0.08	$0.05	$1.48	$1.55
Diluted	0.08	0.05	1.47	1.54
Dividends declared per share of common stock	0.455	0.445	0.910	0.890

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2013	June 30, 2012	December 31, 2012
Assets:			
Current assets:			
Cash and cash equivalents	$12,214	$4,002	$8,923
Accounts receivable	39,061	13,459	61,229
Accrued unbilled revenue	14,692	12,921	56,955
Allowance for uncollectible accounts	(1,189)	(2,653)	(2,518)
Regulatory assets	25,952	65,297	52,448
Derivative instruments	623	2,142	1,950
Inventories	62,412	68,868	67,602
Gas reserves	15,324	11,021	14,966
Income taxes receivable	1,297	3,119	2,552
Other current assets	8,781	8,606	19,592
Total current assets	179,167	186,782	283,699
Non-current assets:			
Property, plant, and equipment	2,833,083	2,720,037	2,786,008
Less: Accumulated depreciation	833,851	791,021	812,396
Total property, plant, and equipment, net	1,999,232	1,929,016	1,973,612
Gas reserves	113,762	65,026	84,693
Regulatory assets	393,652	362,290	382,255
Derivative instruments	1,054	1,170	3,639
Other investments	67,410	68,230	67,667
Restricted cash	4,000	4,000	4,000
Other non-current assets	14,312	13,936	13,555
Total non-current assets	2,593,422	2,443,668	2,529,421
Total assets	$2,772,589	$2,630,450	$2,813,120

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2013	June 30, 2012	December 31, 2012
Liabilities and equity:			
Current liabilities:			
Short-term debt	$136,000	$113,200	$190,250
Accounts payable	63,466	48,361	85,613
Taxes accrued	6,798	5,205	9,588
Interest accrued	6,404	5,607	5,953
Regulatory liabilities	16,644	20,748	20,792
Derivative instruments	9,392	29,407	10,796
Other current liabilities	34,446	42,336	45,444
Total current liabilities	273,150	264,864	368,436
Long-term debt	691,700	641,700	691,700
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	469,964	438,217	444,377
Regulatory liabilities	294,202	280,295	288,113
Pension and other postretirement benefit liabilities	214,125	185,844	215,792
Derivative instruments	1,754	2,130	578
Other non-current liabilities	79,145	82,665	74,497
Total deferred credits and other non-current liabilities	1,059,190	989,151	1,023,357
Commitments and contingencies (see Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,972, 26,827, and 26,917 at June 30, 2013 and 2012 and December 31, 2012, respectively	359,772	352,955	356,571
Retained earnings	397,603	389,247	382,347
Accumulated other comprehensive loss	(8,826)	(7,467)	(9,291)
Total equity	748,549	734,735	729,627
Total liabilities and equity	$2,772,589	$2,630,450	$2,813,120

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

In thousands	Six Months Ended June 30, 2013	2012
Operating activities:		
Net income	$39,765	$41,511
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	37,737	36,049
Deferred tax liabilities	28,401	28,346
Non-cash expenses related to qualified defined benefit pension plans	2,773	4,109
Contributions to qualified defined benefit pension plans	(4,200)	(18,400)
Deferred environmental expenditures, net of recoveries	(2,989)	(3,925)
Other	3,403	1,459
Changes in assets and liabilities:		
Receivables	63,102	114,117
Inventories	5,190	5,495
Taxes accrued	(1,535)	(1,616)
Accounts payable	(22,155)	(37,854)
Interest accrued	451	(250)
Deferred gas costs	(648)	(11,830)
Other, net	10,847	18,171
Cash provided by operating activities	160,142	175,382
Investing activities:		
Capital expenditures	(55,055)	(61,552)
Utility gas reserves	(34,397)	(27,060)
Proceeds from sale of assets	6,580	—
Other	1,743	61
Cash used in investing activities	(81,129)	(88,551)
Financing activities:		
Common stock issued, net	2,355	2,910
Long-term debt retired	—	(40,000)
Change in short-term debt	(54,250)	(28,400)
Cash dividend payments on common stock	(24,509)	(23,839)
Other	682	667
Cash used in financing activities	(75,722)	(88,662)
Increase (decrease) in cash and cash equivalents	3,291	(1,831)
Cash and cash equivalents, beginning of period	8,923	5,833
Cash and cash equivalents, end of period	$12,214	$4,002
Supplemental disclosure of cash flow information:		
Interest paid	$21,746	$21,652
Income taxes paid	—	2,648

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 material 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 six months ended June 30, 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. The amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	June 30,		December 31,
In thousands	2013	2012	2012
Current:			
Unrealized loss on derivatives(1)	$9,392	$29,407	$10,796
Other(2)	16,560	35,890	41,652
Total current	$25,952	$65,297	$52,448
Non-current:			
Unrealized loss on derivatives(1)	$1,754	$2,130	$578
Pension balancing(3)	20,327	10,611	14,727
Income tax asset	53,065	63,452	55,879
Pension and other postretirement benefit liabilities(3)	191,312	162,767	182,688
Environmental costs(4)	120,224	113,369	121,144
Other(2)	6,970	9,961	7,239
Total non-current	$393,652	$362,290	$382,255

	Regulatory Liabilities		
	June 30,		December 31,
In thousands	2013	2012	2012
Current:			
Gas costs	$6,353	$12,980	$9,100
Unrealized gain on derivatives(1)	547	2,142	1,950
Other(2)	9,744	5,626	9,742
Total current	$16,644	$20,748	$20,792
Non-current:			
Gas costs	$481	$1,504	$—
Unrealized gain on derivatives(1)	1,054	1,170	3,639
Accrued asset removal costs	289,105	274,756	281,213
Other(2)	3,562	2,865	3,261
Total non-current	$294,202	$280,295	$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) 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.

(3) 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.

(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. For further information on environmental matters, see Note 13 and Note 15.

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New Accounting Standards

Recent Accounting Pronouncements

OBLIGATIONS RESULTING FROM JOINT AND SEVERAL LIABILITY ARRANGEMENTS. In February 2013, the Financial Accounting Standards Board (FASB) issued guidance regarding the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. This new guidance does not apply to obligations previously addressed within existing guidance. Under the new guidance, an entity is required to measure those fixed obligations as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, an entity must disclose the nature and amount of the obligation as well as other information about the obligations. The guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. We are currently assessing the impact, if any, of this guidance on our financial position, results of operations, and disclosures.

Subsequent Events

Two stipulated settlements were filed with the OPUC on July 11, 2013 with regards to the implementation of our new environmental recovery mechanism and the recovery of carrying costs on working gas inventory. See Note 15 for more information.

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 June 30,		Six Months Ended June 30,	
In thousands, except per share data	2013	2012	2013	2012
Net income	$2,126	$1,227	$39,765	$41,511
Average common shares outstanding - basic	26,958	26,812	26,943	26,797
Additional shares for stock-based compensation plans outstanding	41	84	48	82
Average common shares outstanding - diluted	26,999	26,896	26,991	26,879
Earnings per share of common stock - basic	$0.08	$0.05	$1.48	$1.55
Earnings per share of common stock - diluted	$0.08	$0.05	$1.47	$1.54
Additional information:				
Anti-dilutive shares excluded from net income per diluted common share calculation	43	1	28	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 also includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). 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 Mist, and all third-party asset management services. Our “other” segment includes NNG Financial and NWN Energy's equity 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.

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

	Three Months Ended	Three Months Ended June 30,		
In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$123,943	$7,715	$56	$131,714
Depreciation and amortization	17,311	1,619	—	18,930
Income from operations	9,437	3,625	21	13,083
Net income	657	1,452	17	2,126
Capital expenditures	32,134	247	—	32,381
2012				
Operating revenues	$95,938	$7,996	$57	$103,991
Depreciation and amortization	16,478	1,621	—	18,099
Income from operations	8,547	3,264	28	11,839
Net income (loss)	130	1,124	(27)	1,227
Capital expenditures	40,786	319	—	41,105

	Three Months Ended	Six Months Ended June 30,		
In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$393,602	$15,861	$112	$409,575
Depreciation and amortization	34,499	3,238	—	37,737
Income from operations	79,665	7,582	42	87,289
Net income (loss)	36,688	3,088	(11)	39,765
Capital expenditures	54,522	533	—	55,055
Total assets at June 30, 2013	2,469,320	287,341	15,928	2,772,589
2012				
Operating revenues	$398,843	$14,675	$112	$413,630
Depreciation and amortization	32,816	3,233	—	36,049
Income from operations	84,511	5,943	51	90,505
Net income (loss)	39,598	1,930	(17)	41,511
Capital expenditures	60,442	1,110	—	61,552
Total assets at June 30, 2012	2,326,919	287,622	15,909	2,630,450
Total assets at December 31, 2012	2,505,655	291,568	15,897	2,813,120

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues less revenue taxes and 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 commodity cost of sales like the utility and, therefore, use operating revenues and net income to assess performance.

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2013	2012	2013	2012
Utility margin calculation:				
Utility operating revenues	$123,943	$95,938	$393,602	$398,843
Less: Utility cost of gas	59,142	34,498	201,501	204,253
Utility margin	$64,801	$61,440	$192,101	$194,590

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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.

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. As of June 30, 2013, there was $1.9 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2017. 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 June 30, 2013, there was $0.3 million of unrecognized compensation cost from grants of stock options issued 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 six months ended June 30, 2013.

6. DEBT

Short-Term Debt

At June 30, 2013, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 57 days, an average maturity of 43 days, and an outstanding balance of $136.0 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 June 30, 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 six months ended June 30, 2012, we did not issue or redeem any FMBs.

At June 30, 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.

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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.

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:

	June 30,		December 31,
In thousands	2013	2012	2012
Carrying amount	$691,700	$641,700	$691,700
Estimated fair value	769,679	768,429	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 June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2013	2012	2013	2012
Service cost	$2,341	$2,130	$179	$177
Interest cost	4,104	4,304	286	315
Expected return on plan assets	(4,678)	(4,639)	—	—
Amortization of net actuarial loss	4,421	3,844	169	103
Amortization of prior service costs	55	49	49	49
Amortization of transition obligations	—	—	—	103
Net periodic benefit cost	6,243	5,688	683	747
Amount allocated to construction	(1,801)	(1,428)	(211)	(215)
Amount deferred to regulatory balancing account[1]	(2,271)	(2,094)	—	—
Net amount charged to expense	$2,171	$2,166	$472	$532

	Three Months Ended Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2013	2012	2013	2012
Service cost	$4,682	$4,260	$358	$354
Interest cost	8,207	8,608	572	629
Expected return on plan assets	(9,356)	(9,277)	—	—
Amortization of net actuarial loss	8,842	7,687	338	206
Amortization of prior service costs	111	98	98	98
Amortization of transition obligations	—	—	—	206
Net periodic benefit cost	12,486	11,376	1,366	1,493
Amount allocated to construction	(3,656)	(2,846)	(430)	(429)
Amount deferred to regulatory balancing account[1]	(4,620)	(4,162)	—	—
Net amount charged to expense	$4,210	$4,368	$936	$1,064

[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

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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	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Beginning balance	$(9,058)	$(9,291)
Amounts reclassified into AOCL	—	—
Amounts reclassified from AOCL:		
Amortization of prior service costs	(2)	(4)
Amortization of actuarial losses	385	771
Total reclassifications before tax	383	767
Tax expense	(151)	(302)
Total reclassifications for the period	232	465
Ending balance	$(8,826)	$(8,826)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plan
In the six months ended June 30, 2013, we made cash contributions totaling $4.2 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 $8 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 $0.2 million for the six months ended June 30, 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 to this plan.

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 $1.6 million and $1.2 million for the six months ended June 30, 2013 and 2012, respectively.

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

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8. INCOME TAX

The effective income tax rate varied from the combined federal and state statutory tax rates principally due to the following:

	June 30, 2013		2012	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.6		4.8	
Amortization of investment and energy tax credits	(0.3	)	(0.3	)
Differences required to be flowed-through by regulatory commissions	2.3		1.5	
Gains on company and trust-owned life insurance	(0.8	)	(0.7	)
Other, net	(0.1	)	0.3	
Effective income tax rate	40.7	%	40.6	%

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:

In thousands	June 30, 2013	2012	December 31, 2012
Utility plant in service	$2,468,853	$2,363,061	$2,435,886
Utility construction work in progress	61,283	54,039	46,831
Less: Accumulated depreciation	807,652	770,825	789,201
Utility plant, net	1,722,484	1,646,275	1,693,516
Non-utility plant in service	296,167	296,619	296,781
Non-utility construction work in progress	6,780	6,318	6,510
Less: Accumulated depreciation	26,199	20,196	23,195
Non-utility plant, net	276,748	282,741	280,096
Total property, plant, and equipment	$1,999,232	$1,929,016	$1,973,612

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10. GAS RESERVES

We have 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 6% and 3% of our gas supplies for the six months ended June 30, 2013 and 2012, respectively. 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. The following table outlines our net investment in gas reserves:

	June 30,		December 31,
In thousands	2013	2012	2012
Gas reserves, current	$15,324	$11,021	$14,966
Gas reserves, non-current	126,215	69,097	92,179
Less: Accumulated amortization	12,453	4,071	7,486
Total gas reserves	129,086	76,047	99,659
Less: Deferred tax liabilities on gas reserves	39,963	26,839	28,329
Net investment in gas reserves	$89,123	$49,208	$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. PGH is a development stage VIE and Palomar is reported 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 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. 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.

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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 as well as to hedge spot purchases of natural gas. The following table presents the absolute notional amounts related to open positions on financial derivative instruments:

Dollars in thousands	June 30, 2013	2012	December 31, 2012
Open position absolute notional amount:			
Natural gas (millions of therms)	35.9	35.1	39.5
Foreign exchange	$17,171	$13,725	$13,231

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years and 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.

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. We also enter into exchange contracts related to the optimization of our gas portfolio, which are derivatives but do not qualify for hedge accounting or regulatory deferral, and are subject to our regulatory sharing agreement.

	Three Months Ended			
	June 30, 2013		June 30, 2012	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Cost of sales increase (decrease)	$(16,139)	$—	$27,780	$—
Other comprehensive loss	—	(274)	—	(237)
Less:				
Amounts deferred to regulatory accounts	16,069	274	(27,780)	237
Total loss in pre-tax earnings	$(70)	$—	$—	$—

	Six Months Ended			
	June 30, 2013		June 30, 2012	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Cost of sales increase (decrease)	$(8,956)	$—	$(28,114)	$—
Other comprehensive loss	—	(513)	—	(111)
Less:				
Amounts deferred to regulatory accounts	9,032	513	28,114	111
Total gain in pre-tax earnings	$76	$—	$—	$—

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No collateral was posted with or by our counterparties as of June 30, 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 financial derivative contracts outstanding, which reflect unrealized losses of $8.8 million at June 30, 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	$—	$—	$—	$—	$6,337
Without Adequate Assurance Calls	—	—	—	—	6,180

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. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Generally set-off of any early termination amount payable to one party by the other party, in circumstances where there is a defaulting party or where there is one affected party in the case where either a credit event upon merger has occurred, the occurrence of an event of default or any other termination event, will, at the option of the non-defaulting party be reduced by or set-off against any other amounts payable. If netted by counterparty, our derivative position would result in an asset of $0.2 million and $0.9 million and a liability of $9.7 million and $29.1 million as of June 30, 2013 and June 30, 2012, respectively.

In the three and six months ended June 30, 2013, we realized a net gain of $1.4 million and a net loss of $4.0 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as decreases and increases to the cost of gas, compared to net losses of $21.3 million and $50.7 million, respectively, for the three and six months ended June 30, 2012. 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 June 30, 2013. As of June 30, 2013 and 2012 and December 31, 2012, the fair value was a liability of $9.5 million, $28.2 million, and $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 six months ended June 30, 2013 and 2012.

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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. Actual cost recovery under SRRM depends upon future insurance recoveries, future expenditures, annual prudence reviews, and the impacts of an earnings test. 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. See Note 15 for information on the settlement agreement filed with the OPUC to resolve implementation issues for SRRM.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Item 3. Legal Proceedings). In the complaint, NW Natural sought damages in excess of the $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional losses it expected 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		
	June 30,		December 31,	June 30,		December 31,
In thousands	2013	2012	2012	2013	2012	2012
Portland Harbor site:						
Gasco/Siltronic Sediments	$427	$2,340	$2,207	$38,058	$43,066	$36,087
Other Portland Harbor	1,729	1,286	1,767	2,598	3,409	3,160
Gasco Uplands site	11,354	12,606	18,722	8,230	10,769	5,028
Siltronic Uplands site	496	467	637	392	620	379
Central Service Center site	100	100	140	338	436	396
Front Street site	475	866	993	178	646	—
Oregon Steel Mills	—	—	—	179	117	185
Total	$14,581	$17,665	$24,466	$49,973	$59,063	$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:

In thousands	June 30, 2013	2012	December 31, 2012
Cash paid	$83,936	$62,468	$71,124
Total regulatory asset deferral[1]	120,224	113,369	121,144

[1] Total regulatory asset deferral includes cash paid, remaining liability, and interest, net of 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 $38.5 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 $4.5 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 $10.7 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. This range has uncertainty 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. 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. Historically we had 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 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 impacts of this revision for the years ended December 31:

	2012			2011			2010		
In thousands, except per share data	Reported Balance	Adjustment	Adjusted Balance	Reported Balance	Adjustment	Adjusted Balance	Reported Balance	Adjustment	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 impacts 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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In thousands, except per share data	2011 First Quarter Reported Balance	First Quarter Adjusted Balance	Second Quarter Reported Balance	Second Quarter Adjusted Balance	Third Quarter Reported Balance	Third Quarter Adjusted Balance	Fourth Quarter Reported Balance	Fourth Quarter 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

In thousands, except per share data	Six months ended June 30, 2012 Reported Balance	Six months ended June 30, 2012 Adjusted Balance	Nine months ended September 30, 2012 Reported Balance	Nine months ended September 30, 2012 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

15. SUBSEQUENT EVENTS

Regulatory Settlements

On July 11, 2013, NW Natural filed stipulated settlement agreements in two dockets that resulted from certain decisions deferred by the OPUC from our 2012 general rate case. One settlement addresses implementation issues related to the new environmental recovery mechanism (SRRM), and the second settlement relates to the recovery of carrying costs on working gas inventory. The settlement agreements are subject to Commission review and approval. The Company anticipates Commission review during the third quarter.

Environmental Cost (SRRM) Settlement

If approved, the settlement addresses SRRM implementation issues including a review of the prudence of past deferred expenses, as well as the creation and application of an earnings test to determine the amount of environmental costs that would be collected from customers based on the Company's past and future earnings.

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Under the settlement agreement, approximately $97.6 million of environmental remediation expenses and associated carrying costs incurred by NW Natural through December 31, 2012 were deemed prudently incurred. The parties also agreed that insurance settlements finalized through 2012 (approximately $40.7 million) were prudently executed, with these recoveries applied against deferred expenses to reduce amounts to be amortized under the SRRM. As part of the settlement, NW Natural has agreed not to seek recovery of $7.0 million of its $97.6 million in deferred expenses and associated carrying costs incurred through December 31, 2012. Upon Commission approval, this disallowance and other related adjustments will result in a one-time, net after-tax charge of $3.4 million.

The settlement also provides that environmental remediation expenditures deferred on or after January 1, 2013 will be reviewed annually for prudency, and an earnings test will be applied annually as follows:

- If NW Natural's Oregon utility results of operations (ROO) for a given year show that NW Natural's earnings were more than 75 basis points below its authorized return on equity in that year (Authorized ROE), NW Natural will be allowed to collect all of the prudently incurred environmental remediation expenses deferred in that year.
- If NW Natural's ROO for a given year shows that its earnings are between 75 basis points below Authorized ROE and Authorized ROE (or at Authorized ROE), NW Natural will reduce the balance of the SRRM account up to the net amount deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year (Net Amount Deferred), by 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are above Authorized ROE but less than or equal to 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year, by: (1) 80% of NW Natural's earnings between Authorized ROE and 50 basis points above Authorized ROE; and (2) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are more than 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year, by: (1) 95% of its earnings above 50 basis points above Authorized ROE; (2) 80% of its earnings between Authorized ROE and 50 basis points above Authorized ROE; and (3) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.

Any insurance proceeds recovered after December 31, 2012 will be applied against expenses approved for amortization in the SRRM in equal amounts over the 10-year period following receipt of the funds.

The settlement also provides for recovery of the Company's costs associated with the construction of a water treatment station at NW Natural's Gasco site in Portland, Oregon. The station is currently under construction and is expected to be completed in the third quarter of 2013 with a cost estimate between $20 million and $25 million. Under the settlement agreement, NW Natural can file for rate recovery upon completion and after a prudency review. After these steps, the approved capital costs will be rolled into customer rates as part of rate base at the time of the subsequent PGA.

Working Gas Inventory Settlement

The working gas inventory carrying costs settlement, if approved, would allow the Company to collect $4.5 million, before interest, for deferred carrying costs on working gas inventory balances for the period of November 1, 2012 through October 31, 2013. Upon approval, this amount will be included in the 2013-2014 PGA rates. Prior to the settlement, the Company had been accruing $4.0 million annually for these carrying costs.

In addition, beginning November 1, 2013, approximately $39.5 million in working gas inventory will be included in rate base at NW Natural's authorized utility rate of return. This equates to an annual revenue requirement increase of approximately $4.5 million.

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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 and six months ended June 30, 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 and six 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, including and 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.” Our utility segment includes our NW Natural local gas distribution business, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). 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 Mist, and all third-party asset management services. Our “other” segment includes NWN Energy's 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 equity investment in Kelso-Beaver Pipeline (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 June 30,		
In thousands, except per share data	2013	2012	Change
Consolidated net income	$2,126	$1,227	$899
Consolidated EPS	0.08	0.05	0.03
Utility margin	64,801	61,440	3,361

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to results were as follows:

- an increase in consolidated net income and EPS primarily due to higher utility margin, partially offset by higher operations and maintenance expenses, and depreciation expense.
- an increase in utility margin primarily related to revenue timing impacts, customer growth, and increased contributions from our gas reserve investment. Partially offsetting this margin increase were lower gains from gas cost savings.

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

- signing settlement agreements for both our Site Remediation and Recovery Mechanism (SRRM) and Working Gas Inventory dockets, which, if approved, will resolve two of the open items from our 2012 Oregon general rate case. See "Regulatory Matters—General Rate Cases—Settlements" below for more detail;
- planning continues for the next gas storage expansion at our Mist facility and is expected to include the development of gas storage wells, a compressor station, and additional pipeline facilities; and
- developing new utility service opportunities such as the Company owning and servicing CNG fueling stations at customer locations.

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 continued to show some signs of growth during the second quarter of 2013; however, the economy remains delicate and the recovery slow. Our utility’s annual customer growth rate was 1.0% at June 30, 2013, compared to 0.9% at June 30, 2012. The unemployment rates in our region have declined to under 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 commercial businesses to natural gas, as well as industrial customers switching to natural gas due to its price advantage over oil, propane, and other fuels. In addition, government and regulatory policies 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.

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The physical hedges consisted of a combination of gas inventories in storage, local production from the Mist area, and supply region production from utility gas reserve investment. 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 were also hedged at approximately 59% as of June 30, 2013 for the upcoming 2013-14 gas year and between 8% and 25% 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 are allowed to defer certain costs pursuant to regulatory orders. In our most recent general rate case, the Public Utility Commission of Oregon (OPUC) approved the recovery of environmental costs from investigation and site remediation subject to certain conditions as noted in "Results of Operations—Regulatory Matters—Rate Mechanisms" below.

We also recover some of our environmental costs from insurance policies 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 cost sharing, if any, under the new earnings test. See "Regulatory Matters—General Rate Cases—Settlements" below for more detail on the stipulated settlement filed with the OPUC, which outlines implementation issues regarding the SRRM's earnings test. Environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding.

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 committed to customer and employee safety, operational effectiveness, and service quality, as each is a means of 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. To this end, we have upgraded several facilities to enhance business continuity, employee training, safety, productivity, and energy efficiency. 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 including the accelerated completion of bare steel replacement, 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 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

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generation is needed in the Pacific Northwest region to integrate intermittent wind resources into the power system, thereby increasing the associated need for gas storage. As a result, we are in the early planning stage of a new expansion at Mist. This expansion is anchored by an agreement to provide gas storage services to Portland General Electric (PGE) for gas-fired generation facilities at Port Westward, Oregon. Our Mist expansion project is subject to several conditions, including, but not limited to, PGE's approval of projected costs and timelines and its notice to proceed with the project, and NW Natural's filing and approval by the OPUC of a new rate schedule for this service, as well as NW Natural receiving required permits and regulatory approvals for the project. The expansion would likely include the development of new storage wells, a compressor station, and additional pipeline facilities that would also enable more storage expansions in the future. If the project proceeds as currently planned, the earliest timeframe for completing the next expansion would be 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 7.5 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 regional diversity and increased reliability for our system.

The Federal Energy Regulatory Commission (FERC) will regulate the proposed pipeline. 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 received OPUC and Washington Utilities and Transportation Commission (WUTC) acknowledgment of its filed resource plans and after 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, as well as being able to obtain regulatory permits and the necessary commercial support from shippers. See Note 11 for further discussion.

GAS RESERVES. In addition to hedging gas prices with commodity-based 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. Under this agreement, we have invested in working interests in certain gas leases in a 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 sufficient to hedge approximately 8% to 10% of our 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:

In thousands, except per share data	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	QTR Change	YTD Change
Consolidated operating revenues	$131,714	$103,991	$409,575	$413,630	$27,723	$(4,055)
Consolidated operating expenses	118,631	92,152	322,286	323,125	26,479	(839)
Consolidated interest expense, net	11,069	10,464	22,196	21,655	605	541
Consolidated net income	2,126	1,227	39,765	41,511	899	(1,746)
Consolidated EPS	0.08	0.05	1.47	1.54	0.03	(0.07)

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to increased consolidated net income were as follows:

- a $3.4 million increase in utility margin primarily due to:
  - revenue timing impact from changes in fixed monthly charges and the decoupling baseline in rates from our 2012 Oregon general rate case;
  - an increase in utility margin from customer growth; and
  - an increase in utility margin contribution from our gas reserves investment.

  Partially offsetting these increases was a revenue reduction due in part to a lower authorized return on equity resulting from our 2012 Oregon general rate case noted above; and
  - a lower contribution to utility margin from our gas cost incentive sharing mechanism.

- Partially offsetting the utility margin increase was:
  - a $1.1 million increase in operations and maintenance expense due to increased utility payroll and system maintenance and safety costs;
  - a $0.8 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
  - a $0.6 million increase in income tax expense due to higher pre-tax income.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to decreased consolidated net income were as follows:

- a $2.5 million decrease in utility margin primarily due to:
  - revenue timing impact from changes in fixed monthly charges and the decoupling baseline in rates from our 2012 Oregon general rate case;
  - an overall revenue reduction due in part to a lower authorized return on equity also from our 2012 Oregon general rate case mentioned above; and
  - a lower contribution to utility margin from our gas cost incentive sharing mechanism.

  Partially offsetting these losses was an increase in utility margin from customer growth and an increase in utility margin contribution from our gas reserves investment.
- a $1.7 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
- a $0.4 million increase in operations and maintenance expense due to increases in utility payroll expenses and system maintenance and safety costs, partially offset by a decrease in bad debt expense.

Partially offsetting the decrease in margin and increase in depreciation and operations and maintenance expenses was:

- a $1.2 million increase in gas storage operating revenues;
- a $1.1 million decrease in income tax expense due to lower pre-tax income; and
- an increase in other income.

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Dividends

Dividend highlights include:

	Three Months Ended June 30,		
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 August 15, 2013, to shareholders of record on July 31, 2013, currently reflecting an indicated annual dividend rate of $1.82 per share.

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RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation with respect to, among other matters, rates, and terms of service set by the OPUC, WUTC, and FERC. The OPUC and WUTC also regulate our systems of accounts and 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, rates and terms of service set by the OPUC, California Public Utilities Commission (CPUC), and FERC. The OPUC and CPUC also regulate the issuance of securities and our system of accounts. The OPUC and FERC regulate intrastate and interstate storage services, respectively, under a 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.

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, in which the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt. These customer rates went into effect on November 1, 2012.

DEFERRED DOCKETS. 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 its previous 2003 rate case recovery amounts;
- Interstate Storage Sharing - a docket has been opened to review the sharing arrangement whereby we allocate a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services;
- Working Gas Inventory - the Company filed a settlement agreement with the OPUC in July 2013 to resolve this docket. See detail on agreement below in "Settlements"; and
- Site Remediation and Recovery Mechanism (SRRM) - the Company also filed a settlement agreement with the OPUC in July 2013 to address how to apply the mechanism. See "Settlements" and "Environmental Costs" below.

We anticipate Commission review of the working gas inventory and SRRM settlements before year end and expect decisions on the prepaid pension assets and interstate storage sharing open dockets during 2013 or 2014.

SETTLEMENTS. As noted above, on July 11, 2013, NW Natural filed stipulated settlements with all parties to resolve two open dockets from the 2012 Oregon general rate case. The settlements are subject to OPUC review and approval, which the Company expects to be completed during the third quarter.

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SRRM Settlement. If approved, the SRRM settlement agreement resolves all remaining implementation issues, including a review of the prudence of past deferred expenses, as well as the creation and application of an earnings test to determine the amount of costs that would be collected from customers based on the Company's past and future earnings.

Under the settlement agreement, approximately $97.6 million of environmental remediation expenses and associated carrying costs incurred by NW Natural through December 31, 2012 were deemed prudently incurred, with $33,400 disallowed. The parties also agreed that insurance settlements finalized through 2012 (approximately $40.7 million) were entered into prudently, with these recoveries applied against deferred environmental costs to reduce amounts to be amortized under the SRRM. As part of the settlement, NW Natural has agreed not to seek recovery of $7.0 million of its $97.6 million in deferred expenditures and associated carrying costs incurred through December 31, 2012. Upon OPUC approval, this amount and other related adjustments will result in a one-time, net after-tax charge of $3.4 million.

The settlement agreement also provides that environmental remediation expenditures deferred on or after January 1, 2013 will be reviewed annually for prudency, and an earnings test applied as follows:

- If NW Natural's Oregon utility results of operations (ROO) for a given year show that NW Natural's earnings were more than 75 basis points below its authorized return on equity in that year (Authorized ROE), NW Natural will be allowed to collect all of the prudently incurred environmental remediation expenses deferred in that year.
- If NW Natural's ROO for a given year shows that its earnings are between 75 basis points below Authorized ROE and Authorized ROE (or at Authorized ROE), NW Natural will reduce the balance of the SRRM account up to the net amount deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year (Net Amount Deferred), by 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are above Authorized ROE but less than or equal to 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred, including offsetting insurance proceeds and other third-party recoveries allocated to that year for the current year, by: (1) 80% of NW Natural's earnings between Authorized ROE and 50 basis points above Authorized ROE; and (2) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are more than 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year for the current year, by: (1) 95% of its earnings above 50 basis points above Authorized ROE; (2) 80% of its earnings between Authorized ROE and 50 basis points above Authorized ROE; and (3) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.

For example, assuming that the amount of NW Natural's current Oregon rate base remains unchanged and that NW Natural had earned its Authorized ROE (currently 9.5%) when the earning test was applied, NW Natural would not recover approximately the first $0.6 million of its net environmental remediation expenditures for that year.

Any insurance proceeds recovered after December 31, 2012 will be applied against expenses approved for amortization in the SRRM in equal amounts over the 10-year period following receipt of the funds.

This settlement agreement also provides for recovery of NW Natural's costs associated with the construction of a water treatment station at the Gasco site in Portland, Oregon. The station is currently under construction and is expected to be completed in the third quarter of 2013 with a cost estimate between $20 million and $25 million. Under the settlement agreement, NW Natural will request rate recovery in the upcoming annual PGA filing upon completion of the project. After these steps and prudency review, the approved environmental costs will be rolled into customer rates as part of rate base.

Working Gas Inventory Settlement. The working gas inventory carrying costs settlement, if approved, would allow the Company to collect $4.5 million, before interest, for deferred carrying costs on working gas inventory balances for the period of November 1, 2012 through October 31, 2013. Upon approval, this amount will be included in the PGA rates that become effective November 1, 2013.

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In addition, approximately $39.5 million in working gas inventory will be included in rate base at NW Natural's authorized utility rate of return and be included in PGA rates that become effective November 1, 2013. This equates to an annual revenue requirement increase of approximately $4.5 million.

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.

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 $4 million of capital costs, and an annual cap on expenditures of $12 million, are not included in the amounts tracked into rates. During the second quarter of 2013, the Commission approved an additional $13.7 million of expenditures over the next two years to be tracked into rates. 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 bare steel replacement costs into rates 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 allows the Company to recover prudently incurred environmental site remediation costs, net of insurance recoveries. The SRRM allows 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 been defined in the settlement mentioned above and is awaiting OPUC approval. This test compares earnings in a year to our Authorized ROE with certain levels of sharing of environmental expenditures from that year at graduated levels above and below our Authorized ROE. For more detail on the test, see "General Rate Cases--Settlements" above.

The WUTC has also authorized the deferral of environmental costs that are allocated to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding. Based on the Washington proceeding and our filed settlement in Oregon noted above, 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. The settlement also addresses allocation of costs to Oregon, but the Washington allocation has not been determined. For detail on the Oregon environmental settlement, see "General Rate Cases--Settlements" above and Note 15. See Note 13 for further discussion of our regulatory and insurance recovery of environmental costs.

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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 long-term debt. However, upon collection of these deferred balances, we also receive and recognize the equity portion of our weighted average cost of capital as specified by the OPUC. 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 and $4.6 million being deferred for the three and six months ended June 30, 2013, respectively.

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 the second quarter of 2013, the Company received 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 related to non-utility Mist storage services and asset management services. Last year, the OPUC approved a $9.2 million credit to Oregon customers 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 June 30,		Six Months Ended June 30,			
In thousands, except per share data	2013	2012	2013	2012	QTR Change	YTD Change
Utility net income	$657	$130	$36,688	$39,598	$527	$(2,910)
EPS - utility segment	$0.02	$0.01	$1.36	$1.47	$0.01	$(0.11)
Gas sold and delivered (in therms)	212,097	219,017	612,287	627,176	(6,920)	(14,889)
Utility margin[1]	$64,801	$61,440	$192,101	$194,590	$3,361	$(2,489)

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

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the increase in net income were as follows:

- a $3.4 million increase in utility margin primarily due to:

a $3.0 million increase related to timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case; and

a $1.4 million increase related to customer growth and the rate-base return on our gas reserve investment.

Partially offsetting these increases was a $0.4 million decrease related to the general rate decrease primarily due to our lower Oregon authorized ROE of 9.5% and a $0.9 million decrease in gains from gas cost incentive sharing.

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- Partially offsetting the above margin factors were:
  - a $1.6 million increase in operations and maintenance expense due to increases in utility payroll and expenses related to system maintenance and safety costs;
  - a $0.8 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
  - a $0.5 million increase in income taxes due to higher pre-tax utility income.

Total utility volumes sold and delivered decreased 3% over last year primarily due to the impact of 14% warmer weather on residential and commercial use. As the second quarter is a non-heating quarter, weather does not significantly impact volumes or margin.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the decrease in net income were as follows:

- a $2.5 million decrease in utility margin primarily due to:
  - a $2.2 million decrease related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 rate case;
  - a $1.1 million decrease related to the general rate decrease primarily reflecting the lower Oregon authorized ROE of 9.5%; and
  - a $3.0 million decrease in gains from gas cost incentive sharing due to actual gas prices that were roughly equivalent to estimated PGA prices for the current year as compared to actual gas prices that were lower than estimated PGA prices for the prior year.

  Partially offsetting these decreases was a $3.2 million increase related to customer growth and the rate-base return on our gas reserve investment.
- a $1.7 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 was a $1.6 million decrease in income taxes due to lower pre-tax utility income.

Total utility volumes sold and delivered decreased 2% over last year primarily due to the impact of warmer weather on residential and commercial use.

TIMING IMPACTS. As a result of changes to the utility's 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. Also, customers' fixed monthly charges were increased in the rate case, which allows the Company to recover more of its costs through a higher fixed charge, rather than through the previous volumetric charge, which was more seasonal in nature.

In addition, our weather normalization mechanism was extended through the end of May instead of May 15. This aligns the period covered by our weather normalization mechanism with our decoupling mechanism and further reduces the effect of weather on earnings during this quarter.

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UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes, revenues, and costs of sales. Certain prior year amounts in the following table have been reclassified to conform with the current year's presentation. These reclassifications reflect miscellaneous revenue amounts allocated to 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 June 30,		Six Months Ended Three Months Ended June 30,		Favorable/(Unfavorable)	
	2013	2012	2013	2012	QTR	YTD
Utility volumes - therms:						
Residential and commercial sales	103,313	107,771	371,977	383,930	(4,458)	(11,953)
Industrial sales and transportation	108,784	111,246	240,310	243,246	(2,462)	(2,936)
Total utility volumes sold and delivered	212,097	219,017	612,287	627,176	(6,920)	(14,889)
Utility operating revenues:						
Residential and commercial sales	$110,155	$83,706	$366,521	$370,720	$26,449	$(4,199)
Industrial sales and transportation	15,723	13,232	34,748	35,543	2,491	(795)
Other revenues	1,242	1,578	2,771	3,013	(336)	(242)
Less: Revenue taxes	3,177	2,578	10,438	10,433	599	5
Total utility operating revenues	123,943	95,938	393,602	398,843	28,005	(5,241)
Less: Cost of gas	59,142	34,498	201,501	204,253	24,644	(2,752)
Utility margin	$64,801	$61,440	$192,101	$194,590	$3,361	$(2,489)
Utility margin:(1)						
Residential and commercial sales	$57,343	$52,715	$174,706	$174,130	$4,628	$576
Industrial sales and transportation	6,527	6,751	14,245	14,387	(224)	(142)
Miscellaneous revenues	1,242	1,371	2,771	2,966	(129)	(195)
Gain (loss) from gas cost incentive sharing	(413)	452	129	3,089	(865)	(2,960)
Other margin adjustments	102	151	250	18	(49)	232
Utility margin	$64,801	$61,440	$192,101	$194,590	$3,361	$(2,489)
Customers - end of period:						
Residential customers	622,534	617,039	622,534	617,039	5,495	5,495
Commercial customers	64,598	62,975	64,598	62,975	1,623	1,623
Industrial customers	935	922	935	922	13	13
Total number of customers - end of period	688,067	680,936	688,067	680,936	7,131	7,131
Actual degree days	591	705	2,495	2,659		
Percent colder (warmer) than average weather(2)	(14)%	3%	(2)%	4%		

(1) Amounts reported as margin for each category of customer include 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 and six months ended June 30, 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:

In thousands	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	QTR Change	YTD Change
Volumes - therms:						
Residential sales	61,775	64,097	231,725	240,134	(2,322)	(8,409)
Commercial sales	41,538	43,674	140,252	143,796	(2,136)	(3,544)
Total volumes	103,313	107,771	371,977	383,930	(4,458)	(11,953)
Operating revenues:						
Residential sales	$71,742	$54,938	$243,910	$249,777	$16,804	$(5,867)
Commercial sales	38,413	28,768	122,611	120,943	9,645	1,668
Total operating revenues	$110,155	$83,706	$366,521	$370,720	$26,449	$(4,199)
Utility margin:						
Residential:						
Sales	$40,303	$37,634	$124,904	$123,242	$2,669	$1,662
Weather normalization adjustments	929	5	(2,731)	(2,807)	924	76
Decoupling adjustments	(953)	62	1,864	6,263	(1,015)	(4,399)
Total residential utility margin	40,279	37,701	124,037	126,698	2,578	(2,661)
Commercial:						
Sales	16,169	15,314	49,816	48,279	855	1,537
Weather normalization adjustments	410	(24)	(1,228)	(1,027)	434	(201)
Decoupling adjustments	485	(276)	2,081	180	761	1,901
Total commercial utility margin	17,064	15,014	50,669	47,432	2,050	3,237
Total utility margin	$57,343	$52,715	$174,706	$174,130	$4,628	$576

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to changes in residential and commercial sales were as follows:

- sales volumes decreased 4%, primarily driven by warmer weather, but partly offset by customer growth;
- operating revenues increased $26.4 million, primarily due to $34.3 million of credits from gas cost savings which were applied to customer billings in 2012, partially offset by a 9% decrease in average gas prices, which flowed through the Company's PGA rates, and a 4% decrease in sales volumes;
- utility margin increased 9%, primarily reflecting:

a $3.0 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines from the 2012 rate case; and

a $1.4 million increase related to customer growth and the rate-base return on our gas reserve investment.

Partially offsetting these increases was a $0.4 million decrease related to the general rate decrease primarily reflecting our lower Oregon authorized ROE of 9.5%.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to changes in residential and commercial sales were as follows:

- sales volumes decreased 3%, primarily reflecting 6% warmer weather, partially offset by customer growth;
- operating revenues decreased 1% due to a 3% decrease in sales volumes, a 13% decrease in average gas prices, which flowed through the Company's PGA rates, partially offset by $34.3 million of credits from gas cost savings which were applied to customer billings in 2012; and
-

utility margin remained relatively flat, as increases from customer growth and the rate-base return on our gas reserve investment were offset by the negative $2.2 million timing impacts from changes in fixed monthly charges and decoupling baselines in the 2012 rate case.

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Industrial Sales and Transportation

Industrial sales and transportation highlights include:

In thousands	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012	QTR Change	YTD Change
Volumes - therms:						
Industrial - firm sales	7,586	7,593	17,066	18,212	(7)	(1,146)
Industrial - firm transportation	32,456	29,736	72,209	68,587	2,720	3,622
Industrial - interruptible sales	13,443	14,190	30,512	31,920	(747)	(1,408)
Industrial - interruptible transportation	55,299	59,727	120,523	124,527	(4,428)	(4,004)
Total volumes	108,784	111,246	240,310	243,246	(2,462)	(2,936)
Utility margin:						
Industrial - firm and interruptible sales	$2,770	$2,986	$6,454	$6,717	$(216)	$(263)
Industrial - firm and interruptible transportation	3,757	3,765	7,791	7,670	(8)	121
Total utility margin	$6,527	$6,751	$14,245	$14,387	$(224)	$(142)

THREE AND SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. Total sales volumes decreased 2% and utility margin decreased 3% for the second quarter of 2013 compared to 2012 primarily due to lower demand from certain customers in the pulp and paper segment. This decrease in utility margin was partially offset by contributions from new customers. Total sales volumes decreased 1% and utility margin decreased 1% for the six months ended June 30, 2013, compared to the same period in 2012, due to the lower demand from certain customers as previously mentioned.

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 gas price stability. 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 June 30,		Six Months Ended June 30,		QTR	YTD
In thousands, except as noted	2013	2012	2013	2012	Change	Change
Total volumes sold and delivered (therms)	212,097	219,017	612,287	627,176	(6,920)	(14,889)
Cost of gas	$59,142	$34,498	$201,501	$204,253	$24,644	$(2,752)
Average cost of gas (cents per therm)	0.48	0.53	0.48	0.55	(0.05)	(0.07)
Total realized financial hedge gains (losses) on financial swaps	1,436	(21,297)	(3,965)	(50,654)	22,733	46,689
Utility margin gain (loss) from gas cost incentive sharing	(413)	452	129	3,089	(865)	(2,960)

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the $24.6 million increase in cost of gas were as follows:

- a $35.8 million decrease from gas cost savings applied to customer billings in June 2012. Excluding the prior year customer credits, cost of gas decreased $11.2 million or 16%, partially reflecting a 3% decrease in total sales volumes due to warmer weather and lower average gas prices in the current year's PGA;
- average cost of gas collected through rates, excluding prior year customer refunds for gas cost savings, decreased 9%, 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 of $22.7 million were realized and included in cost of gas, resulting in a $1.4 million gain. Since underlying hedge prices are generally included in our PGA billing rates, hedge gains and losses generally do not impact margin or net income results.

The effect on net income from our gas cost incentive sharing mechanism was a pre-tax margin loss of $0.4 million for the second quarter of 2013, compared to a pre-tax margin gain of $0.5 million for the same period in 2012.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the 1% decrease in cost of gas were as follows:

- a $35.8 million decrease from gas cost savings applied to customer billings in June 2012. Excluding the prior year customer credits, cost of gas decreased $38.6 million or 16%, partially reflecting a 2% decrease in total sales volumes due to 6% warmer weather and lower average gas prices in the current year's PGA;
- average cost of gas collected through rates, excluding prior year customer refunds for gas cost savings, decreased 13%, 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 of $46.7 million were realized and included in cost of gas. Since underlying hedge prices are generally included in our PGA billing rates, hedge losses generally do not impact margin or net income results.

The effect on net income from our gas cost incentive sharing mechanism was a pre-tax margin gain of $0.1 million for the six months ended June 30, 2013, compared to $3.1 million pre-tax 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.

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Gas storage segment highlights include:

In thousands, except per share data and as otherwise noted	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012	QTR Change	YTD Change
Gas storage net income	$1,452	$1,124	$3,088	$1,930	$328	$1,158
EPS - gas storage segment	0.05	0.04	0.11	0.07	0.01	0.04
Average gas storage contracted capacity (Bcf)	21	21	21	20	—	1

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the increase in our gas storage segment net income were lower power costs and property taxes at Gill Ranch, as well as higher revenues from third party asset management services. This increase was partially offset by a decrease in firm contract and fuel-in-kind revenues due to lower contracted prices for the 2013-14 gas storage year.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The primary factors contributing to the increase in our gas storage segment net income were lower power costs and property taxes at Gill Ranch, as well as increased revenues from additional storage services. Higher revenues from third party asset management services also contributed to the increase in net income year over year.

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 NNG Financial's equity investment in KB Pipeline, an equity investment in PGH, which in turn has invested in a cross-Cascades pipeline project, and other miscellaneous non-utility investments and business activities.

Other business highlights include:

In thousands	June 30, 2013	2012	Change
Investment in:			
NNG Financial	$933	$871	$62
PGH Investment	13,430	13,455	(25)

THREE AND SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. Our other businesses remained relatively flat over the three and six months ended June 30, 2013 compared to 2012, with net income or loss of less than $0.1 million for each period. 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:

In thousands	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012	QTR Change	YTD Change
Operations and maintenance	$33,217	$32,138	$66,974	$66,570	$1,079	$404

THREE MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The increase in operations and maintenance expense was primarily due to:

- a $1.0 million increase in utility payroll expense primarily related to accrued incentive compensation, as well as an increase in field service employees; and
- a $0.5 million increase in utility expenses related to system maintenance and safety costs.

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- Partially offsetting the above factors was a $0.5 million decrease in gas storage expenses driven by power expense management.

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The increase in operations and maintenance expense was primarily due to:
- a $1.2 million increase in utility payroll expense, primarily related to accrued incentive compensation; and
- a $1.0 million increase in utility expenses related to system maintenance and safety costs.

Partially offsetting the factors above were:
- a $1.4 million decrease in utility bad debt expense. See further discussion below;
- a $0.3 million decrease in miscellaneous claim accruals; and
- a $0.2 million decrease in gas storage expenses driven by lower payroll expenses.

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 and six months ended June 30, 2013, we deferred pension expenses totaling $2.3 million and $4.6 million, respectively, and $2.1 million and $4.2 million for the same periods last year. 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.

Depreciation and Amortization

Depreciation and amortization expense highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2013	2012	2013	2012	Change	Change
Depreciation and amortization	$18,930	$18,099	$37,737	$36,049	$831	$1,688

THREE AND SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. Depreciation and amortization expense increased both for the three and six months ended June 30, 2013 compared to 2012 due to a higher level of investment in utility property, plant, and equipment.

Other Income and Expense, Net

Other income and expense, net highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2013	2012	2013	2012	Change	Change
Other income and expense, net	$1,450	$620	$1,970	$1,092	$830	$878

THREE AND SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. Other income and expense, net increased both for the three and six months ended June 30, 2013 compared to 2012 due to increased interest income on Oregon regulatory asset balances.

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Interest Expense

Interest expense highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2013	2012	2013	2012	Change	Change
Interest expense	$11,069	$10,464	$22,196	$21,655	$605	$541

THREE AND SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. Interest expense increased both for the three and six months ended June 30, 2013 compared to 2012 due to increases in average balances of short- and long-term debt outstanding.

Income Tax Expense

Income tax expense highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
Dollars in thousands	2013	2012	2013	2012	Change	Change
Income tax expense	$1,338	$768	$27,298	$28,431	$570	$(1,133)
Effective tax rate	38.6%	38.5%	40.7%	40.6%	0.1%	0.1%

THREE AND SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. Income tax expense increased in the second quarter of 2013 due to an increase in pre-tax consolidated earnings compared to the second quarter of 2012. The decrease in income tax expense for the six months ended June 30, 2013, compared to the same period in 2012, was due to lower pre-tax consolidated earnings. 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 were relatively unchanged for the three and six months ended June 30, 2013 compared to the same periods in 2012.

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:

	June 30,		December 31,
	2013	2012	2012
Common stock equity	47.5%	49.3%	45.3%
Long-term debt	43.9	43.1	42.9
Short-term debt, including any current maturities of long-term debt	8.6	7.6	11.8
Total	100%	100%	100%

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Liquidity and Capital Resources

At June 30, 2013, we had $12.2 million of cash and cash equivalents compared to $4.0 million at June 30, 2012. We also had $4.0 million in restricted cash at Gill Ranch at both June 30, 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 June 30, 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 June 30, 2013, we could have been required to post $6.3 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 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.

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, equity investments 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 June 30, 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.

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Under the debt agreement, 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 June 30, 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.

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 June 30, 2013 and 2012, our utility had commercial paper outstanding of $136.0 million and $113.2 million, respectively. The effective interest rate on the utility’s commercial paper outstanding at June 30, 2013 and 2012 was 0.3%.

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 June 30, 2013 as follows:

In thousands	
Lender rating, by category	Loan Commitment
AA/Aa	$189,000
A/A1	111,000
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 June 30, 2013 or 2012. Like the former credit agreement, the current 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 June 30, 2013 and 2012, with consolidated indebtedness to total capitalization ratios of 52.5% and 50.7%, 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.

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 six months ended June 30, 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:

	Six Months Ended June 30,		
In thousands	2013	2012	Change
Cash provided by operating activities	$160,142	$175,382	$(15,240)

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The significant factors contributing to the decrease in operating cash flow were as follows:

- a decrease of $51.0 million from changes in the accounts receivable balance, which was significantly reduced in June 2012 from customer credit refunds;

Partially offsetting this decrease was:

- an increase of $15.7 million from changes in accounts payable due to a smaller reduction in gas costs in the first six months of 2013 compared to 2012.
- an increase of $14.2 million due to decreased 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

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an increase of $11.2 million from changes in the deferred gas costs balance, which reflects a lower variance between actual gas prices and embedded gas prices in the PGA for 2013 compared to 2012, as well as credit refunds to customers in June 2012.

During the six months ended June 30, 2013, we contributed $4.2 million to our utility's qualified defined benefit pension plans, which was higher than the $2.8 million in non-cash expense recognized on the income statement, compared to contributions of $18.4 million and $4.1 million in non-cash expense for the same six 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.

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 June 30, 2013, we had an estimated federal income tax receivable balance of $1.3 million and an estimated NOL carry-forward balance of $74.4 million. In 2011 and 2012, Oregon conformed with federal bonus depreciation, contributing to a state NOL carryforward of $80.0 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:

	Six Months Ended June 30,		
In thousands	2013	2012	Change
Total cash used in investing activities	$81,129	$88,551	$(7,422)
Capital expenditures	55,055	61,552	(6,497)
Utility gas reserves	34,397	27,060	7,337
Proceeds from sale of assets	(6,580)	—	(6,580)

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The $7.4 million decrease in cash used in investing activities was primarily due to lower capital expenditures on facilities projects and proceeds received from the sale of assets, partially offset by increased investment in utility gas reserves. 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:

	Six Months Ended June 30,		
In thousands	2013	2012	Change
Total cash used in financing activities	$75,722	$88,662	$(12,940)
Change in short-term debt	54,250	28,400	25,850
Long-term debt retired	—	40,000	(40,000)
Cash dividend payments	24,509	23,839	670

SIX MONTHS ENDED JUNE 30, 2013 COMPARED TO JUNE 30, 2012. The decrease in cash used in financing activity was primarily due to $40 million of long-term debt retired in the first quarter of 2012, partially offset by changes in our short-term debt balances, which increased $54.3 million in the first six months of 2013 compared to $28.4 million for the same period in 2012. We continue to use long-term debt proceeds to finance utility capital expenditures, refinance maturing debt, and to fund other general corporate purposes.

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Ratios of Earnings to Fixed Charges
For the six and twelve months ended June 30, 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 3.89, 3.16, 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 in the first quarter of 2013. See Note 14 for detail on the prior period correction and Exhibit 12 for the detailed ratio calculation.

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 June 30, 2013, we had a regulatory asset of $120.2 million for deferred environmental costs, which includes $64.6 million for additional costs expected to be paid in the future and $19.5 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 more detail on environmental recovery, see "Regulatory Matters—General Rate Cases—Settlements" above. 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 six month period ending June 30, 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 June 30, 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 June 30, 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
04/01/13 - 04/30/13	—	$—	—	—
05/01/13 - 05/31/13	2,827	45.28	—	—
06/01/13 - 06/30/13	—	—	—	—
Total	2,827	$45.28	2,124,528	$ 16,732,648

[1] During the quarter ended June 30, 2013, 2,827 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended June 30, 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, 2014 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended June 30, 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: August 7, 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 June 30, 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 June 30, 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.