NORTHWEST NATURAL GAS CO
Form 10-Q
August 03, 2012

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, 2012

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______ to _______

Commission File No. 1-15973

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

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

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [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 27, 2012, 26,831,575 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, 2012

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

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

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

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Consolidated Statements of Comprehensive Income
(Unaudited)

Thousands, except per share amounts	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating revenues:				
Gross operating revenues	$106,569	$161,197	$424,063	$484,285
Less: Cost of sales	34,512	90,122	204,283	270,747
Revenue taxes	2,578	3,843	10,433	11,798
Net operating revenues	69,479	67,232	209,347	201,740
Operating expenses:				
Operations and maintenance	32,124	30,374	66,540	61,546
General taxes	7,417	6,659	16,253	14,824
Depreciation and amortization	18,099	17,546	36,049	34,855
Total operating expenses	57,640	54,579	118,842	111,225
Income from operations	11,839	12,653	90,505	90,515
Other income and expense - net	921	1,122	1,926	2,336
Interest expense - net	10,464	10,266	21,655	20,715
Income before income taxes	2,296	3,509	70,776	72,136
Income tax expense	887	1,316	28,760	29,170
Net income	1,409	2,193	42,016	42,966
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $109 and $96 for the three months and $217 and $192 for the six months ended June 30, 2012 and 2011, respectively	166	146	332	292
Comprehensive income	$1,575	$2,339	$42,348	$43,258
Average common shares outstanding:				
Basic	26,812	26,673	26,797	26,671
Diluted	26,896	26,727	26,879	26,725
Earnings per share of common stock:				
Basic	$0.05	$0.08	$1.57	$1.61
Diluted	$0.05	$0.08	$1.56	$1.61
Dividends declared per share of common stock	$0.445	$0.435	$0.890	$0.870

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
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Consolidated Balance Sheets
(Unaudited)

Thousands	June 30, 2012	June 30, 2011	December 31, 2011
Assets:			
Current assets:			
Cash and cash equivalents	$4,002	$3,700	$5,833
Restricted cash	-	925	-
Accounts receivable	13,459	39,104	77,449
Accrued unbilled revenue	12,921	15,031	61,925
Allowance for uncollectible accounts	(2,653)	(2,824)	(2,895)
Regulatory assets	65,297	59,766	94,673
Derivative instruments	2,142	4,433	2,853
Inventories	68,868	71,229	74,363
Gas reserves	11,021	749	4,463
Income taxes receivable	3,119	26,285	7,045
Other current assets	8,606	9,496	22,980
Total current assets	186,782	227,894	348,689
Non-current assets:			
Property, plant and equipment	2,720,037	2,612,147	2,661,102
Less: Accumulated depreciation	791,021	744,929	767,226
Total property, plant and equipment - net	1,929,016	1,867,218	1,893,876
Gas reserves	65,026	15,403	47,451
Regulatory assets	366,981	326,081	371,392
Derivative instruments	1,170	1,042	-
Other investments	68,230	68,576	68,263
Restricted cash	4,000	-	4,000
Other non-current assets	13,936	15,780	12,903
Total non-current assets	2,448,359	2,294,100	2,397,885
Total assets	$2,635,141	$2,521,994	$2,746,574

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets
(Unaudited)

Thousands	June 30, 2012	June 30, 2011	December 31, 2011
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,827, 26,673, and 26,756 at June 30, 2012 and 2011 and December 31, 2011, respectively	$352,955	$344,451	$348,383
Retained earnings	392,082	376,489	373,905
Accumulated other comprehensive income (loss)	(7,467)	(6,312)	(7,800)
Total common stock equity	737,570	714,628	714,488
Long-term debt	641,700	551,700	641,700
Total capitalization	1,379,270	1,266,328	1,356,188
Current liabilities:			
Short-term debt	113,200	185,400	141,600
Current maturities of long-term debt	-	40,000	40,000
Accounts payable	48,361	54,148	86,300
Taxes accrued	5,205	6,805	10,747
Interest accrued	5,607	5,127	5,857
Regulatory liabilities	20,748	25,784	31,046
Derivative instruments	29,407	25,986	57,317
Other current liabilities	42,336	37,574	41,597
Total current liabilities	264,864	380,824	414,464
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	440,073	398,825	413,209
Regulatory liabilities	280,295	265,703	278,382
Pension and other postretirement benefit liabilities	185,844	130,985	201,530
Derivative instruments	2,130	9,202	6,536
Other non-current liabilities	82,665	70,127	76,265
Total deferred credits and other non-current liabilities	991,007	874,842	975,922
Commitments and contingencies (see Note 13)			
Total capitalization and liabilities	$2,635,141	$2,521,994	$2,746,574

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
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Consolidated Statements of Cash Flows
(Unaudited)

Thousands	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating activities:		
Net income	$42,016	$42,966
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	36,049	34,855
Non-cash expenses related to qualified defined benefit pension plans	4,109	3,655
Contributions to qualified defined benefit pension plans	(18,400)	(16,445)
Deferred environmental expenditures, net of recoveries	(3,925)	(1,770)
Other	1,459	(819)
Changes in assets and liabilities:		
Receivables	114,117	79,711
Inventories	5,495	9,156
Taxes accrued	(1,616)	11,007
Accounts payable	(37,854)	(30,052)
Interest accrued	(250)	(55)
Deferred gas costs	(11,830)	2,682
Deferred tax liabilities	28,676	27,516
Other - net	17,336	6,328
Cash provided by operating activities	175,382	168,735
Investing activities:		
Capital expenditures	(61,552)	(47,815)
Utility gas reserves	(27,060)	(16,152)
Other	61	67
Cash used in investing activities	(88,551)	(63,900)
Financing activities:		
Common stock issued (purchased) - net, including common stock expense	2,910	(70)
Long-term debt retired	(40,000)	(10,000)
Change in short-term debt	(28,400)	(72,035)
Cash dividend payments on common stock	(23,839)	(23,204)
Other	667	717
Cash used in financing activities	(88,662)	(104,592)
Increase (decrease) in cash and cash equivalents	(1,831)	243
Cash and cash equivalents - beginning of period	5,833	3,457
Cash and cash equivalents - end of period	$4,002	$3,700
Supplemental disclosure of cash flow information:		
Interest paid	$21,652	$20,770
Income taxes paid	$2,648	$1,522

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements
(Unaudited)

1. Organization and Principles of Consolidation

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

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

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments that management considers necessary for a fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2011 Annual Report on Form 10-K (2011 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

2. Significant Accounting Policies Update

Our significant accounting policies are described in Note 2 of the 2011 Form 10-K. There were no material changes to those accounting policies during the six months ended June 30, 2012. The following are current updates to certain critical accounting policy estimates, subsequent events of the Company, and accounting standards in general.

Regulatory Accounting

In applying regulatory accounting principles in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), we capitalize or defer certain costs and revenues as regulatory assets and liabilities. At June 30, 2012 and 2011 and at December 31, 2011, the amounts deferred as regulatory assets and liabilities were as follows:

Regulatory Assets

	June 30,	June 30,	December 31,

Thousands	2012	2011	2011
Current:			
Unrealized loss on derivatives(1)	$29,407	$25,986	$57,317
Pension and other postretirement benefit liabilities(2)	15,491	10,988	15,491
Other(3)	20,399	22,792	21,865
Total current	$65,297	$59,766	$94,673
Non-current:			
Unrealized loss on derivatives(1)	$2,130	$9,202	$6,536
Pension balancing(2)	10,766	2,659	6,008
Income tax asset	63,452	70,241	65,264
Pension and other postretirement benefit liabilities(2)	162,767	112,743	170,512
Environmental costs(4)	117,905	120,285	105,670
Other(3)	9,961	10,951	17,402
Total non-current	$366,981	$326,081	$371,392

Regulatory Liabilities

Thousands	June 30, 2012	June 30, 2011	December 31, 2011
Current:			
Gas costs	$12,980	$17,538	$17,994
Unrealized gain on derivatives(1)	2,142	4,433	2,853
Other(3)	5,626	3,813	10,199
Total current	$20,748	$25,784	$31,046
Non-current:			
Gas costs	$1,504	$3,023	$8,420
Unrealized gain on derivatives(1)	1,170	1,042	-
Accrued asset removal costs	274,756	259,593	267,355
Other(3)	2,865	2,045	2,607
Total non-current	$280,295	$265,703	$278,382

(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 mechanism when realized at settlement.

(2) Certain pension costs of the utility 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 or earn a rate of return or carrying charge (see Note 8).

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

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

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Subsequent Events

See Note 14 for information regarding the private placement bond purchase agreement entered into on July 12, 2012 and Note 7 for more detail on our debt.

New Accounting Standards

Recent Accounting Pronouncements

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

3. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands, except per share amounts	2012	2011	2012	2011
Net income	$1,409	$2,193	$42,016	$42,966
Average common shares outstanding - basic	26,812	26,673	26,797	26,671
Additional shares for stock-based compensation plans outstanding (See Note 6)	84	54	82	54
Average common shares outstanding - diluted	26,896	26,727	26,879	26,725
Earnings per share of common stock - basic	$0.05	$0.08	$1.57	$1.61
Earnings per share of common stock - diluted	$0.05	$0.08	$1.56	$1.61
Antidilutive shares	1,180	8,946	943	3,883

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4. Segment Information

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

The following table presents summary financial information about the reportable segments for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2012				
Net operating revenues	$61,440	$7,996	$43	$69,479
Depreciation and amortization	16,478	1,621	-	18,099
Income from operations	8,547	3,264	28	11,839
Net income (loss)	312	1,124	(27)	1,409
2011				
Net operating revenues	$60,048	$7,197	$(13)	$67,232
Depreciation and amortization	15,946	1,600	-	17,546
Income (loss) from operations	9,667	3,017	(31)	12,653
Net income (loss)	1,090	1,315	(212)	2,193

	Six Months Ended June 30,			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2012				
Net operating revenues	$194,590	$14,675	$82	$209,347
Depreciation and amortization	32,816	3,233	-	36,049
Income from operations	84,511	5,943	51	90,505
Net income (loss)	40,103	1,930	(17)	42,016
Total assets at June 30, 2012	2,331,610	287,622	15,909	2,635,141
2011				
Net operating revenues	$189,210	$12,501	$29	$201,740
Depreciation and amortization	31,860	2,995	-	34,855
Income (loss) from operations	85,791	4,733	(9)	90,515
Net income (loss)	41,220	2,003	(257)	42,966
Total assets at June 30, 2011	2,247,349	252,393	22,252	2,521,994
Total assets at December 31, 2011	$2,435,888	$294,637	$16,049	$2,746,574

5. Common Stock

We have a share repurchase program for our common stock under which we may purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2013 to repurchase up to an aggregate of 2.8 million shares, but not to exceed $100 million. No shares of common stock were repurchased pursuant to this program during the six months ended June 30, 2012. Since the plan's inception in 2000 a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

6. Stock-Based Compensation

Our stock-based compensation plans include a Long-Term Incentive Plan (LTIP), an Employee Stock Purchase Plan, and a Restated Stock Option Plan (Restated SOP). The Restated SOP was terminated in the second quarter of 2012 as approved by shareholders. Shareholders also approved the amended LTIP and added 250,000 shares to the plan. These plans are designed to promote stock ownership in NW Natural by employees and officers. For additional information on our stock-based compensation plans, see Note 6, in the 2011 Form 10-K and current updates provided below.

Long-Term Incentive Plan

In the second quarter of 2012 shares available for issuance under the LTIP were increased from 600,000 shares to 850,000 shares. The additional 250,000 shares may only be used for option grants under the LTIP and not for full-value awards such as Restricted Stock Units (RSUs) or performance shares.

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

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

Restricted Stock Units. The current LTIP allows for a variety of awards including RSUs to be granted. The RSUs awarded include a performance based threshold and a vesting period of four years from the grant date. The Company is obligated upon vesting of an RSU to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of the RSU. On February 22, 2012, RSUs totaling 21,720 were granted with a grant date fair value of $48.00 per share.

Restated Stock Option Plan

As of June 30, 2012, there was $0.7 million of unrecognized compensation cost from grants of stock options in prior years, which is expected to be recognized over a period extending through 2014. The Restated SOP was terminated in the second quarter of 2012; however, the outstanding options may still be exercised through their expiration dates. Any new grants of stock options would be made under the LTIP; however, no new stock options were granted in the six months ended June 30, 2012.

7. Cost and Fair Value Basis of Debt

Cost and Fair Value of Short-Term Debt

Our short-term debt consists of commercial paper and notes payable with an average maturity date of September 17, 2012 and an outstanding balance of $113.2 million as of June 30, 2012. The fair value of our commercial paper approximates the amortized cost using Level 2 inputs. Level 2 in the fair value hierarchy are inputs that have significant other observable inputs.

Cost of Long-Term Debt

Our utility's long-term debt consists of secured medium-term notes (MTNs) with maturity dates ranging from 2014 through 2035, interest rates ranging from 3.176 percent to 9.05 percent, and a weighted-average coupon rate of 5.85 percent. In March of 2012, we redeemed $40 million of MTNs. See Note 14 for more information regarding the bond purchase agreement for the sale and issuance of first mortgage bonds subsequent to June 30, 2012.

Our gas storage segment's long-term debt consists of $40 million of fixed and variable senior secured notes with a maturity date of November 30, 2016. The $20 million fixed rate notes have an interest rate of 7.75 percent, and the $20 million variable rate notes currently have an interest rate of 7.00 percent. The notes are secured by all of the membership interests in Gill Ranch Storage, LLC and are nonrecourse to NW Natural. See Note 7 in our 2011 Form 10-K for more detail on our long-term debt.

Fair Value of Long-Term Debt

As our outstanding debt does not trade in active markets, we used interest rates of other companies' outstanding debt issuances that actively trade in public markets and have similar credit ratings, terms and remaining maturities to estimate the fair value of our long-term debt issuances. These inputs are Level 2 inputs. 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,
Thousands	2012	2011	2011
Carrying amount	$641,700	$591,700	$681,700
Estimated fair value	$768,429	$678,281	$808,724

8. Pension and Other Postretirement Benefit Costs

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

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2012	2011	2012	2011
Service cost	$ 2,130	$ 1,900	$ 177	$ 168
Interest cost	4,304	4,526	315	343
Expected return on plan assets	(4,639)	(4,456)	-	-
Amortization of net actuarial loss	3,844	2,692	103	68
Amortization of prior service costs	49	88	49	49
Amortization of transition obligations	-	-	103	103
Net periodic benefit cost	5,688	4,750	747	731
Amount allocated to construction	(1,428)	(1,251)	(215)	(229)
Amount deferred to regulatory balancing account(1)	(2,094)	(1,329)	-	-
Net amount charged to expense	$ 2,166	$ 2,170	$ 532	$ 502

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2012	2011	2012	2011
Service cost	$ 4,260	$ 3,799	$ 354	$ 336
Interest cost	8,608	9,053	629	687
Expected return on plan assets	(9,277)	(8,912)	-	-
Amortization of net actuarial loss	7,687	5,384	206	136
Amortization of prior service costs	98	176	98	98
Amortization of transition obligations	-	-	206	206
Net periodic benefit cost	11,376	9,500	1,493	1,463
Amount allocated to construction	(2,846)	(2,486)	(429)	(455)
Amount deferred to regulatory balancing account(1)	(4,162)	(2,659)	-	-
Net amount charged to expense	$ 4,368	$ 4,355	$ 1,064	$ 1,008

(1) Effective January 1, 2011, the Oregon Public Utility Commission (OPUC) approved the deferral of certain pension expenses above or below the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower pension expenses in future years. Deferred pension expense balances include accrued interest at the utility’s authorized rate of return. See "Regulatory Accounting" in Note 2.

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

In the six months ended June 30, 2012, we made cash contributions totaling $18.4 million to our qualified defined benefit pension plans. We also expect to make additional contributions up to $10 million to these qualified plans over the last six months of 2012, plus we expect to make ongoing benefit payments under our unfunded, non-qualified pension plans and other postretirement benefit plans.

Multiemployer Pension and Defined Contribution Plans

In addition to the company-sponsored defined benefit pension plans referred to above, we contribute to a multiemployer pension plan (EIN 94-6076144) for our utility's bargaining unit employees, known as the Western States Office and Professional Employees Pension Fund (Western States Plan), and to defined contribution plans for utility and non-utility employees. The costs of these plans are in addition to pension expense in the table above. Our contributions to the Western States Plan amounted to $0.2 million, for the six months ended June 30, 2012 and 2011, respectively. Under the terms of our current collective bargaining agreement, we can withdraw from the Western States Plan at any time. However, if we withdraw and the plan is underfunded, we could be assessed a withdrawal liability. We do not recognize a liability currently for the Western States Plan because we have made no decision to withdraw from the 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 $1.2 million and $1.3 million for the six months ended June 30, 2012 and 2011, respectively.

See Note 9, in the 2011 Form 10-K for more information about these plans.

9. Income Tax

The effective income tax rate for the six months ended June 30, 2012 and 2011 varied from the combined federal and state statutory tax rates principally due to the following:

	June 30,			
	2012		2011	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.5	%	4.5	%
Amortization of investment and energy tax credits	(0.3	) %	(0.4	) %
Differences required to be flowed-through by regulatory commissions	1.5	%	1.6	%
Gains on company and trust-owned life insurance	(0.7	) %	(0.6	) %
Other - net	0.6	%	0.3	%
Effective income tax rate	40.6	%	40.4	%

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

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NORTHWEST NATURAL GAS COMPANY
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10. Property, Plant and Equipment

The following table sets forth the major classifications of our property, plant and equipment and accumulated depreciation as of June 30, 2012 and 2011 and December 31, 2011:

Thousands	June 30, 2012	June 30, 2011	December 31, 2011
Utility plant in service	$2,363,061	$2,281,407	$2,323,467
Utility construction work in progress	54,039	32,814	36,051
Less: Accumulated depreciation	770,825	730,199	749,603
Utility plant-net	1,646,275	1,584,022	1,609,915
Non-utility plant in service	296,619	290,035	293,205
Non-utility construction work in progress	6,318	7,891	8,379
Less: Accumulated depreciation	20,196	14,730	17,623
Non-utility plant-net	282,741	283,196	283,961
Total property, plant and equipment	$1,929,016	$1,867,218	$1,893,876

11. Gas Reserves and Other Investments

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

Gas Reserves

We entered into agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop and produce physical gas reserves that are expected to supply a portion of NW Natural's utility customers' requirements over 30 years. Encana began drilling in 2011 under these agreements, and we are currently receiving gas from our interests in a section of the gas field. Our cost of gas and the carrying cost of the investment are included in our annual Oregon Purchased Gas Adjustment (PGA) filing and recovered through rates in a manner previously approved by the OPUC. This transaction accounted for approximately 3% of our gas supplies for the six months ended June 30, 2012. The following table outlines our net investment at June 30, 2012 and 2011 and December 31, 2011:

Thousands	June 30, 2012	June 30, 2011	December 31, 2011
Gas reserves, current	$11,021	$749	$4,463
Gas reserves, non-current	69,097	15,403	48,597
Less: Accumulated amortization	4,071	-	1,146
Total gas reserves	76,047	16,152	51,914
Less: Deferred taxes on gas reserves	26,839	3,440	15,630

Net investment in gas reserves	$49,208	$12,712	$36,284

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

Palomar

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

Variable Interest Entity (VIE) Analysis. As of June 30, 2012, there were no changes to our VIE analysis and we continue not to be the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations due to the fact that we have a 50 percent share and there are no stipulations that allow disproportionate influence over the entity. Therefore, we account for our investment in PGH and the Palomar project under the equity method, which is included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50 percent owner.

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

Our investment balance in Palomar was $13.5 million at June 30, 2012, which consists of costs related to the east segment. We are continuing to work on development of commercial support and Palomar expects to file a new Federal Energy Regulatory Commission (FERC) certification application to reflect a revised scope based on regional needs for the eastern segment of the proposed Palomar pipeline project. However, if we learn later that the project is not viable or will not go forward, we could be required to recognize a maximum charge of up to approximately $13.2 million based on the current amount of our equity investment net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required. See Note 12 in our 2011 Form 10-K for more detail on Palomar and our annual impairment analysis.

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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 prices related to our natural gas purchase requirements. A small portion of our derivative hedging strategy involves foreign currency exchange transactions related to purchases of natural gas from Canadian suppliers.

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

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments for the three and six months ended June 30, 2012 and 2011. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting standards.

	Three Months Ended			
	June 30, 2012		June 30, 2011	
Thousands	Natural gas commodity(1)	Foreign currency (2)	Natural gas commodity(1)	Foreign currency (2)
Cost of sales	$ 27,780	$-	$ 3,631	$-
Other comprehensive income (loss)	-	(237)	-	(196)
Less:				
Amounts deferred to regulatory accounts on balance sheet	(27,780)	237	(3,631)	196
Total impact on earnings	$ -	$-	$ -	$-

	Six Months Ended			
	June 30, 2012		June 30, 2011	
Thousands	Natural gas commodity(1)	Foreign currency (2)	Natural gas commodity(1)	Foreign currency (2)
Cost of sales	$ (28,114)	$-	$ (30,119)	$-
Other comprehensive income (loss)	-	(111)	-	406
Less:				
Amounts deferred to regulatory accounts on balance sheet	28,114	111	30,119	(406)
Total impact on earnings	$ -	$-	$ -	$-

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

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

No collateral was posted with or by our counterparties as of June 30, 2012 or 2011. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and diversification, we have not been subject to collateral calls in 2011 or 2012. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current contracts outstanding, which reflect unrealized losses of $28.2 at June 30, 2012, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various downgrade credit rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$-	$-	$-	$15,342
Without Adequate Assurance Calls	$ -	$-	$-	$-	$19,222

In the three and six months ended June 30, 2012, we realized net losses of $21.3 million and $50.7 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas, compared to net losses of $8.7 million and $29.6 million, respectively, for the three and six months ended June 30, 2011. The exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

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

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, 2012. As of June 30, 2012 and 2011 and December 31, 2011, the fair value was $28.2 million, $29.7 million and $61.0 million, respectively, using significant other observable, or Level 2, inputs. We have used no Level 3 inputs in our derivative valuations. We did not have any transfers between Level 1 or Level 2 during the six months ended June 30, 2012 and 2011.

13. Commitments and Contingencies

Environmental Matters

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

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

We estimate the range of loss for environmental liabilities using current 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. 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 uncertainty concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives. The status of each of the sites currently under investigation is provided below.

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

EPA ultimately selects for the entire Portland Harbor Superfund site. The 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. On June 22, 2012, EPA delivered a notice of non-compliance to the LWG with respect to the Baseline Human Health Risk Assessment the LWG submitted to EPA in May 2011 (BHHRA), as a component of the RI. The LWG has disputed the EPA's claims that the BHHRA is in any way deficient or noncompliant and has initiated formal dispute resolution under the 2001 Administrative Settlement Agreement and Order on Consent issued by EPA to LWG.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with EPA to evaluate and design specific remedies for sediments adjacent to the Gasco upland and Siltronic upland sites. The Gasco/Siltronic Sediments is part of the Portland Harbor Superfund site. 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. The EE/CA will provide a variety of remedial alternatives for the sediments at this site. The alternatives provided in the EE/CA are based on EPA requirements to develop costs for the various remedies described therein. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA range from $34 million to $350 million. After the EPA determines an appropriate alternative from the EE/CA, a remedial design will be produced. We have recorded a liability of $34.0 million for the sediment clean-up, which reflects the low end of the EE/CA range. We have recorded an additional liability of $11.4 million for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up. At this time, we believe the sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above. We accrued at the low end because no amount within the range is considered to be more likely than another.

Portland Harbor RI/FS and natural resource damage claims. NW Natural incurs costs related to its membership in the Lower Willamette Group which is performing the RI/FS for EPA. NW Natural also incurs costs related to natural resource damages. In 2008, the Portland Harbor Natural Resource Trustee Council advised a number of potentially responsible parties that it intended to pursue natural resource damage claims at the Portland Harbor Superfund site. The Company and other parties have signed a cooperative agreement with the Natural Resource Trustees to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. As of June 30, 2012, we have an accrued liability of $4.7 million for these claims, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated at this time. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

Gasco upland site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site). The Gasco upland site is adjacent to the Portland Harbor site described above and has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site. In June 2003, we filed a Feasibility Scoping Plan which outlined a range of remedial alternatives for the most contaminated portion of the Gasco upland site. In December 2004, we submitted an Ecological and Human Health Risk Assessment to ODEQ, and in May 2007 we completed a revised Remedial Investigation Report and submitted it to ODEQ for review. The liability accrued at June 30, 2012 for the Gasco upland site is $8.6 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

In 2007, we also submitted a Focused Feasibility Study (FFS) for the groundwater source control portion of the Gasco site, which ODEQ conditionally approved in March 2008, subject to the submission of additional information. We provided that information to ODEQ and are now working with the agency on the final design for the source control system. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding remediation, we have estimated a range of liability between $14 million and $30 million, for which we have recorded an accrued liability of $14.8 million at June 30, 2012. The estimated range of liability will be reassessed when ODEQ makes a final source control design decision.

Siltronic upland site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic upland site). The Siltronic upland site is also adjacent to the Portland Harbor site, but not included in the range of remedial costs for the Portland Harbor site. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The liability accrued at June 30, 2012 for the Siltronic site is $1.1 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2008, we received notice that this site was added to the ODEQ's list of sites in which releases of hazardous substances have been confirmed. ODEQ has also added this site to its list of sites where cleanup is necessary. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. As of June 30, 2012, we have a liability accrued of $0.5 million for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. It is near but outside the geographic scope of the current Portland Harbor site sediment studies. The EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that it could be managed separately from the Portland Harbor site under ODEQ authority. Work plans for source control investigation and a historical report were submitted to ODEQ and initial studies were completed. In 2010, ODEQ required additional studies which were completed in 2012. The results of those studies have been presented to ODEQ and a final sampling plan required by ODEQ is currently being developed. As of June 30, 2012, we have an estimated liability accrued of $1.5 million for the study of the sediments and riverbank groundwater and soils at the site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

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

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at June 30, 2012 and 2011 and December 31 2011, which are recorded in other current liabilities and other noncurrent liabilities on the balance sheet:

	Current Liabilities			Non-Current Liabilities		
Thousands	June 30, 2012	June 30, 2011	Dec. 31, 2011	June 30, 2012	June 30, 2011	Dec. 31, 2011
Portland Harbor site:						
Gasco/Siltronic Sediments	$2,340	$995	$1,614	$43,066	$29,866	$35,797
Other Portland Harbor	1,286	2,619	1,893	3,409	5,426	7,066
Gasco site	12,606	9,140	14,092	10,769	9,099	8,900
Siltronic upland site	467	836	887	620	71	128
Central Service Center site	100	5	-	436	543	495
Front Street site	866	-	1,697	646	823	-
Other sites	-	-	-	117	132	120
Total	$17,665	$13,595	$20,183	$59,063	$45,960	$52,506

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

On a cumulative basis, we have recognized a total of $133.4 million for environmental costs, including legal, investigation, monitoring and remediation costs, and $4.9 million paid and expensed prior to regulatory deferral order approval. At June 30, 2012, we had a regulatory asset of $117.9 million.

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

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

Legal Proceedings

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

On July 12, 2012, NW Natural entered into a bond purchase agreement under which a group of investors agreed to purchase $50 million of our first mortgage bonds with a coupon rate of 4.00 percent and a 30 year maturity. The bond issuance is subject to customary closing conditions and is expected to close on or before October 31, 2012. The proceeds of the issuance are to be used to reduce short-term debt and for other general corporate purposes.

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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, the Company or we) 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, 2012 and 2011. Unless otherwise indicated, references below to "Notes" are to the Notes to Consolidated Financial Statements in this report. A significant portion of our business results are seasonal in nature, and as such the results of operations for 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 2011 Annual Report on Form 10-K (2011 Form 10-K).

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

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

Executive Summary

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

- Consolidated earnings of $1.4 million or 5 cents per share in 2012, compared to $2.2 million or 8 cents per share in 2011;
- Net income from utility operations decreased $0.8 million, from $1.1 million in 2011 to $0.3 million in 2012;
- Net income from gas storage operations decreased $0.2 million, from $1.3 million in 2011 to $1.1 million in 2012;
- Net operating revenues (margins) increased $2.2 million or 3 percent over 2011, with utility margins up $1.4 million and gas storage margins up $0.8 million;
- Operating expenses increased $3.0 million or 6 percent over 2011;
- Cash flow from operating activities was $175.4 million for the six months ended June 30, 2012, an increase of $6.6 million or 4 percent over 2011;
-

Customer refunds totaling $39 million related to lower wholesale natural gas costs were credited to customer bills beginning in June 2012; and

- Utility customer count increased by approximately 5,900 over the last 12 months, for an annual growth rate of 0.9 percent compared to 0.8 percent a year ago.

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Issues, Challenges and Performance Measures

Economic environment. Weakness in the local, national and global economies continued to impact utility customer growth, business demand for natural gas and market prices for gas storage. Our utility's annual customer growth rate was 0.9 percent at June 30, 2012, as compared to 0.8 percent at both March 31, 2012 and June 30, 2011. The local economy is beginning to show signs of a slow recovery, with unemployment rates in Oregon and southwest Washington declining from 2011 to 2012. We believe our utility business is well positioned to continue adding customers and to serve increasing industrial demand as the economy recovers because of low, stable natural gas prices, our relatively low market penetration, our focus on converting homes and businesses to natural gas, and the potential for environmental initiatives favoring natural gas use in our region.

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

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

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

Besides the amount hedged for the current gas contract year, we are also hedged at approximately 59 percent for the 2012-13 gas year as of June 30, 2012. We have also entered into gas reserve purchases and financial hedge transactions that hedge gas prices beyond this upcoming gas contract year. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather and economic conditions. In addition, our storage inventory levels may increase or decrease based on storage expansion or storage recall by the utility. The utility added 1 Bcf to its off-system storage capacity in October 2011 by entering into a three-year contract with a third-party for natural gas storage located in Canada, for which injections began in April 2012. We expect recovery of our off-system storage costs, including demand charges and other operating costs, through our normal PGA mechanism. As for gas reserve purchases and Mist area gas production, we include estimates in our hedge levels, which are subject to change based on possible unforeseen events including the impact from the pace of drilling activity and the volume of production from each well.

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

Environmental clean-up costs. We continue to accrue all material loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the development of or remediation solutions approved by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we have been allowed to defer certain costs pursuant to regulatory decisions. We currently have regulatory authority to defer certain environmental costs and to seek recovery of those costs in future customer rates. However, we are expected to pursue recovery from insurance policies first and to seek recovery from customers only for amounts not recovered from insurance. Any amounts collected from insurance are expected to offset amounts that may otherwise be collected from customers. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage these costs and demonstrate that costs were prudently incurred. Recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. See Results of Operations—Regulatory Matters—Rate Mechanisms—Regulatory Recovery for Environmental Costs below, Note 13 in this report and Note 15 in our 2011 Form 10-K.

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

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Strategic Opportunities

Increased investment in safety and service. To best respond to new federal pipeline safety legislation and system integrity management regulatory requirements, as well as increasing customer expectations for service responsiveness, the Company has increased staffing levels in the areas of pipeline safety, emergency response, regulatory compliance, field training, and customer service. We also continue to improve upon the quality and integrity of our pipeline infrastructure, and have initiated several facility upgrades to enhance business continuity, employee training and safety, productivity and energy efficiency. We remain committed to finding new ways to improve operational effectiveness and capitalize on our competitive position and service quality.

Gas storage developments. We currently own and operate two underground gas storage facilities—the Mist facility in Oregon and the Gill Ranch facility in Fresno, California. Our Mist facility currently consists of 16 Bcf of available storage capacity, with 10 Bcf allocated to the utility business and 6 Bcf allocated to the gas storage business. Our wholly-owned subsidiary, Gill Ranch holds a 75 percent undivided ownership interest in the Gill Ranch facility; Pacific Gas and Electric Company (PG&E) owns the other 25 percent interest. Our Gill Ranch facility currently consists of 15 Bcf of available storage capacity. Future expansion is possible at both the Mist and Gill Ranch storage facilities to serve increasing demand should the market for gas storage improve. For more information, see Note 4 in this report and Part II, Item 7., "2012 Outlook—Strategic Opportunities," in our 2011 Form 10-K.

Due to an abundant supply of natural gas and lower, more stable prices in North America, storage values are expected to remain relatively low in the near term, which will likely affect the prices at which Gill Ranch is able to contract. Gas prices hit a 10-year low in early 2012, and this has resulted in certain natural gas producers reducing their levels of exploration and production. At the same time, we expect these lower gas prices to increase national demand for natural gas as the lower pricing provides a competitive advantage over alternative energy sources including the potential for switching coal plants over to natural gas and increasing demand for exporting natural gas. Combined, these demand forces, and reduced drilling activity, may ultimately result in upward pressure on gas prices and return some price volatility to natural gas markets.

Our storage facilities position us well to capitalize on rising demand for natural gas, higher gas prices or increased market volatility because storage operations benefit from seasonal swings in commodity prices and market volatility. Additionally, if market demand increases and we are able to obtain regulatory permits and project financing, we have the ability to expand the Mist and Gill Ranch facilities beyond their current capacities. Gill Ranch for instance, can develop increased storage capacity without further expansion of our gas transmission pipeline. We estimate that the current Gill Ranch storage facility could support an additional 20 Bcf of storage capacity, bringing total capacity up to 40 Bcf with certain infrastructure modifications, of which we would have the rights to 50 percent of the total.

The Pacific Northwest storage markets are also impacted by lower gas prices and lack of gas price volatility, although less than California markets primarily because of fewer regional competitors. Nevertheless, we continue to plan for expansion of our gas storage facilities at Mist in anticipation of increased natural gas demand for electric generation in the Pacific Northwest. During the second quarter of 2012, a request for proposals (RFP) to provide additional energy generation was sent out by Portland General Electric (PGE). As part of the RFP process, PGE has submitted its own "benchmark" bids that other third party bids must compete with. The Company has an agreement to provide storage services to PGE should their bid be selected. Other third party bidders are free to make their own gas supply arrangements in support of their bids.

We are continuing to evaluate future expansion at Mist; however, we do not currently have a set timeline for development. We believe the earliest timeframe for completing the next Mist expansion is 2016. In the meantime, we expect to continue working on preliminary design and scope of the next expansion, which will likely include the development of storage wells, a second compression station and additional pipeline gathering facilities.

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

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

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

In July of 2012, various federal agencies including the Bureau of Land Management, the U.S. Forest Service and the U.S. Department of Energy entered into a Settlement Agreement resolving litigation filed in 2009 by a number of environmental groups. The Agreement requires the agencies to periodically review the energy corridors on a regional basis to assess the need for potential revisions. We do not anticipate any material changes in our plans for Palomar due to this settlement.

Gas reserves. In addition to hedging gas prices with financial swap and option contracts, we signed an agreement with Encana in 2011 to acquire physical gas supplies to meet a portion of our utility customers' requirements over 30 years. During the first 10 years, we forecast the volumes of gas received under the Encana agreements to provide approximately 8 to 10 percent of the average annual requirements of our utility customers. Under the agreement, we expect to invest approximately $45 million to $55 million per year for five years, subject to certain NW Natural rights to terminate the agreement, with our total investment expected to be about $250 million. We pay a fixed portion of drilling costs per well, and Encana assigns to us working interests in leases to certain sections of the Jonah gas field, located near Rock Springs, Wyoming. These sections include both future and currently producing wells. The working interest entitles us to receive a portion of the gas produced in the assigned sections. Operation of the wells is governed by a joint operating agreement under which Encana is the operator, and we pay our proportionate share of the operating costs. We receive federal tax deductions associated with drilling costs. The timing of when the Company realizes federal tax benefits from these drilling costs may be affected by net operating losses for tax purposes, which will be carried forward to reduce our current tax liability in future years. See Note 10 and Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves below and Part II, Item 7., "2012 Outlook—Strategic Opportunities," in our 2011 Form 10-K.

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Consolidated Earnings and Dividends

Three months ended June 30, 2012 compared to June 30, 2011:

For the three months ended June 30, 2012, we had net income of $1.4 million, or 5 cents per share, compared to net income of $2.2 million, or 8 cents per share, for the same period last year.

The primary factors contributing to decreased second quarter consolidated net income were:

- a $1.8 million increase in operations and maintenance expense primarily due to increases in utility payroll and employee benefit costs;
- a $0.8 million increase in general taxes primarily due to an increase in gas storage property taxes for Gill Ranch's completed, in-service property assessed values; and
- a $0.6 million increase in depreciation and amortization expenses primarily due to a higher level of investment in property, plant and equipment at the utility and gas storage operations.

Partially offsetting the above factors was:

- a $1.4 million increase in utility net operating revenues (margins) primarily due to a one-time, pre-tax charge of $7.4 million recorded in the second quarter of 2011 related to Senate Bill 408, partially offset by a decrease in utility margin from the effects of warmer weather in the second quarter of 2012 compared to 2011.

Six months ended June 30, 2012 compared to June 30, 2011:

Net income was $42.0 million, or $1.56 per share, for the six months ended June 30, 2012, compared to $43.0 million, or $1.61 per share, for the same period last year.

The primary factors contributing to the $1.0 million decrease in net income were:

- a $5.0 million increase in operations and maintenance expense due to increases in utility payroll and employee benefit costs, utility training costs, and expenses related to our Oregon general rate case;
- a $1.4 million increase in general taxes primarily due to increased property taxes at Gill Ranch;
- a $1.2 million increase in depreciation and amortization expenses primarily due to higher levels of investment in property, plant and equipment at the utility and gas storage operations; and
- a $0.9 million increase in interest expense primarily due to the new debt issuance at Gill Ranch late in 2011.

Partially offsetting the above factors were:

- a $5.4 million net increase in utility margin primarily due to a one-time, pre-tax charge of $7.4 million in 2011 related to Senate Bill 408, and an increase of $2.0 million for gains related to gas cost savings, partially offset by a decrease in utility margin from the effects of warmer weather in 2012 compared to 2011; and
- a $2.2 million net increase in gas storage margin primarily attributable to revenue increases from Gill Ranch from additional contracted storage capacity, partially offset by margin decreases from Mist operations due to lower storage prices and lower optimization revenues.

Dividends paid on our common stock were 44.5 cents per share in the second quarter of 2012, compared to 43.5 cents per share in the second quarter of 2011. The Board of Directors declared a quarterly dividend on our common stock of 44.5 cents per share, payable on August 15, 2012, to shareholders of record on July 31, 2012. The current indicated annual dividend rate is $1.78 per share.

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Application of Critical Accounting Policies and Estimates

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

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

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

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.

Results of Operations

Regulatory Matters

Regulation and Rates

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

Gas Storage. Our gas storage business is subject to regulation with respect to, among other matters, issuance of securities and systems of accounts set by the OPUC, California Public Utilities Commission (CPUC), and FERC. The

OPUC and FERC regulate our Mist gas storage business under a maximum cost-based rate model, whereas the CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2011, approximately 65 percent of our storage revenues were derived from OPUC and FERC approved cost-based rates, and approximately 35 percent were from CPUC approved market-based rates.

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

Oregon General Rate Case

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

On May 3, 2012, the parties involved in NW Natural's general rate case filed their testimony, which represents their first filing in the formal administrative proceeding through which the OPUC determines rate cases. These included the Staff of the OPUC, the Citizen's Utility Board (CUB), and the Northwest Industrial Gas Users (NWIGU). In its testimony, the OPUC Staff recommended a revenue requirement reduction of $10.7 million, or a 1.5 percent decrease, compared to our requested $43.7 million or 6.2 percent increase. Staff's testimony is based on a 7.56 percent overall cost of capital including a 9.2 percent return on common equity, and reductions to various operation and maintenance (O&M) expenses and capital additions requested. These parties also recommended certain modifications to our proposed environmental cost recovery mechanism, modifications to an existing allocation of revenues to customers from our interstate gas storage operations and denial of our request for recovery of certain costs related to our contributions covering employee pension benefits. The filings made by CUB and NWIGU overlap with Staff's proposals in several areas while also recommending additional reductions to O&M and capital additions.

On June 15, 2012, we filed our rebuttal testimony reflecting the effects of a partial stipulation agreement and other revisions to our original filed case. Our revised case now requests a $35.9 million increase (5.1 percent) reflecting an overall rate of return of 8.14 percent based upon an ROE of 10.2 percent and a capital structure of 50 percent common equity.

On July 9, 2012, we filed along with several parties to the case, including Staff, CUB, and NWIGU, a partial stipulation resolving several issues in the case. The partial stipulation was the result of settlement conferences held May 22 and 23, 2012. While we were able to reach agreement on several issues, we were unable to resolve terms on capital structure, rate of return and other issues.

On July 20, 2012, the parties involved in the case filed their rebuttal testimony, responding to our June 15th testimony. In the filings, they made modifications to certain of the recommendations made in their May 3rd filing. These changes include a modification of OPUC Staff's recommendation on NW Natural's revenue requirement, which now proposes an increase to NW Natural's revenue requirement of $8.4 million, compared to our revised request of a $35.9 million increase.

Throughout the formal administrative proceeding, NW Natural and the parties have the opportunity to engage in settlement discussions regarding any or all of the issues involved in the proceeding. We have engaged in such discussions during scheduled settlement conferences. We are unable at this time to predict the outcome of this rate proceeding, or to predict which, if any, issues will be presented to the OPUC as part of a contested proceeding or as part of a settlement proposal. The remaining schedule includes two days of hearings beginning on August 23, 2012 after which the final order is due on October 22, 2012. The effective date of the new rates will be November 1, 2012.

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Rate Mechanisms

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

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

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

In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings review to determine if the utility is earning above its authorized return on equity (ROE) threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for both the 2010-2011 and the 2011-2012 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2010 and 2011, the ROE threshold after adjustment for long-term interest rates was 11.02 percent and 10.92 percent, respectively. We refunded $0.2 million to customers based on the 2010 utility earnings test, and we expect to refund $0.7 million to customers in the upcoming PGA year based upon the 2011 utility earnings test. We do not expect to be subject to a refund for the 2012 earnings test year.

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

The WUTC has also authorized the deferral of environmental costs, if any, that are incurred in connection with services provided to Washington customers. The order granting approval of that request was effective January 26, 2011. See Note 13 for further discussion of our regulatory and insurance recovery of environmental costs.

Pension Deferral. Effective January 1, 2011, the OPUC approved our request to defer annual pension expense above the amount set in rates in our last general rate case. The recovery of these deferred pension costs will be through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of deferred balances includes accrued interest on the account balance at the utility’s authorized rate of return, which is currently 8.62 percent. The reduction to operations and maintenance expense in 2011 was $6.0

million. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities using a number of key assumptions, as well as being affected by pension contributions by the Company. We estimate pension expense deferrals totaling $8 million to $9 million in 2012, with $2.1 million and $4.2 million being deferred for the three and six months ended June 30, 2012, respectively.

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

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

For a discussion of other rate mechanisms, see Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2011 Form 10-K.

Business Segments - Utility Operations

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

Three months ended June 30, 2012 compared to June 30, 2011:

Utility operations resulted in net income of $0.3 million, or 1 cent per share, in the second quarter of 2012 compared to net income of $1.1 million, or 4 cents per share, in the second quarter of 2011. The decrease in net income was primarily due to higher operating expenses and the effects of warmer weather on margin revenues. These decreases were partially offset by increases in margin revenues due to a non-recurring charge related to the repeal of Senate Bill 408 (SB 408) in 2011 and gains from gas cost savings and customer growth in 2012 compared to the same period in 2011.

Gas Utility Volumes, Revenues and Margin

Total utility volumes sold and delivered in the second quarter of this year decreased by 10 percent over last year primarily due to 25 percent warmer weather compared to the prior year, while total utility margin increased by $1.4 million, or 2 percent. The increase in margin was primarily due to a one-time, pre-tax charge in the second quarter of 2011 for $7.4 million related to the repeal of Senate Bill (SB) 408, which did not reoccur in 2012. Excluding the SB 408 charge, margin for the second quarter of 2012 decreased by $6.1 million primarily due to the earnings impact of colder weather in the second quarter of 2011.

Our weather normalization mechanism adjusted residential and commercial margins down by $19 thousand for the second quarter of 2012 based on temperatures that were 3 percent colder than average, compared to a margin decrease of $4.8 million for the second quarter of 2011 when temperatures were 38 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins down by $214 thousand in the second quarter of 2012, compared to a margin increase of $2.2 million in 2011. The positive impact of colder weather in the second quarter of 2011 was disproportionately greater than the impact in the same period of 2012 because the colder weather in 2011 occurred mostly in the month of May when the weather normalization mechanism for customer usage ends on May 15th while the decoupling mechanism assumes weather adjusted volumes for the entire month.

Six months ended June 30, 2012 compared to June 30, 2011:

In the six months ended June 30, 2012, utility operations contributed net income of $40.1 million or $1.49 per share, compared to $41.2 million or $1.54 per share in 2011. The decrease in net income was primarily due to higher operating expenses and the effects of warmer weather on margin revenues, partially offset by increases in margin revenues due to a non-recurring charge related to the repeal of SB 408 in 2011 plus gains from gas cost savings and customer growth in the 2012 period compared to 2011.

Gas Utility Volumes, Revenues and Margin

Total utility volumes sold and delivered in the six months ended June 30, 2012 decreased by 3 percent over last year primarily due to 9 percent warmer weather, while total utility margin increased by $5.4 million, or 3 percent. The increase in margin was primarily due to a one-time, pre-tax charge of $7.4 million in the first six months of 2011 related to the repeal of Senate Bill 408, which did not reoccur in 2012, and a $3.1 million gain, up from $1.1 million last year, from gas cost savings due to lower prices, and a 0.9 percent increase in customer growth, which offset the decline in customer volumes and margins resulting from warmer weather. Excluding the SB 408 charge, margin decreased by $1.8 million primarily due to positive earnings impact of colder weather from the first six months of 2011 as discussed above.

During the six months ended June 30, 2012, our weather normalization mechanism adjusted residential and commercial margins down by $3.8 million based on temperatures that were 4 percent colder than average, compared to a margin decrease of $10.6 million last year when temperatures were 14 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins up by $6.4 million for the six months ended June 30, 2012 and $10.9 million for the six months ended June 30, 2011, to largely offset the impact of lower average use per customer on a weather normalized basis.

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

	Three Months Ended June 30,		Favorable/ (Unfavorable)
Thousands, except degree day and customer data	2012	2011	2012 vs. 2011
Utility volumes - therms:			
Residential sales	64,097	78,349	(14,252)
Commercial sales	43,674	51,232	(7,558)
Industrial - firm sales	7,593	8,476	(883)
Industrial - firm transportation	29,736	32,533	(2,797)
Industrial - interruptible sales	14,190	14,295	(105)
Industrial - interruptible transportation	59,727	57,867	1,860
Total utility volumes sold and delivered	219,017	242,752	(23,735)
Utility operating revenues - dollars:			
Residential sales	$ 54,938	$ 91,765	$ (36,827)
Commercial sales	28,768	48,344	(19,576)
Industrial - firm sales	4,477	6,880	(2,403)
Industrial - firm transportation	1,779	1,628	151
Industrial - interruptible sales	4,955	8,407	(3,452)
Industrial - interruptible transportation	2,021	2,284	(263)
Regulatory adjustment for income taxes paid(1)	-	(7,451)	7,451
Other revenues	1,578	2,088	(510)
Total utility operating revenues	98,516	153,945	(55,429)
Cost of gas sold	34,498	90,054	55,556
Revenue taxes	2,578	3,843	1,265
Utility margin	$ 61,440	$ 60,048	$ 1,392
Utility margin:(2)			
Residential sales	$ 37,634	$ 43,767	$ (6,133)
Commercial sales	15,314	17,229	(1,915)
Industrial - sales and transportation	6,751	6,840	(89)
Miscellaneous revenues	1,371	1,526	(155)
Gain from gas cost incentive sharing	452	87	365
Other margin adjustments	151	632	(481)
Margin before regulatory adjustments	61,673	70,081	(8,408)
Weather normalization adjustment	(19)	(4,751)	4,732
Decoupling adjustment	(214)	2,169	(2,383)
Regulatory adjustment for income taxes paid(1)	-	(7,451)	7,451
Utility margin	$ 61,440	$ 60,048	$ 1,392
Customers - end of period:			
Residential customers	617,039	611,564	5,475
Commercial customers	62,975	62,532	443
Industrial customers	922	906	16
Total number of customers - end of period	680,936	675,002	5,934
Actual degree days	705	944	
Percent colder than average weather(3)	3 %	38 %	

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Thousands, except degree day and customer data	Six Months Ended June 30, 2012	2011	Favorable/ (Unfavorable) 2012 vs. 2011
Utility volumes - therms:			
Residential sales	240,134	253,053	(12,919)
Commercial sales	143,796	150,409	(6,613)
Industrial - firm sales	18,212	19,340	(1,128)
Industrial - firm transportation	68,587	69,015	(428)
Industrial - interruptible sales	31,920	31,532	388
Industrial - interruptible transportation	124,527	120,817	3,710
Total utility volumes sold and delivered	627,176	644,166	(16,990)
Utility operating revenues - dollars:			
Residential sales	$ 249,777	$ 290,602	$ (40,825)
Commercial sales	120,943	143,112	(22,169)
Industrial - firm sales	12,786	15,725	(2,939)
Industrial - firm transportation	3,687	3,374	313
Industrial - interruptible sales	15,003	18,734	(3,731)
Industrial - interruptible transportation	4,067	4,600	(533)
Regulatory adjustment for income taxes paid(1)	-	(7,165)	7,165
Other revenues	3,013	2,690	323
Total utility operating revenues	409,276	471,672	(62,396)
Cost of gas sold	204,253	270,664	66,411
Revenue taxes	10,433	11,798	1,365
Utility margin	$ 194,590	$ 189,210	$ 5,380
Utility margin:(2)			
Residential sales	$ 123,242	$ 128,019	$ (4,777)
Commercial sales	48,279	49,787	(1,508)
Industrial - sales and transportation	14,387	14,450	(63)
Miscellaneous revenues	2,966	3,110	(144)
Gain from gas cost incentive sharing	3,089	1,122	1,967
Other margin adjustments	18	(395)	413
Margin before regulatory adjustments	191,981	196,093	(4,112)
Weather normalization adjustment	(3,834)	(10,612)	6,778
Decoupling adjustment	6,443	10,894	(4,451)
Regulatory adjustment for income taxes paid(1)	-	(7,165)	7,165
Utility margin	$ 194,590	$ 189,210	$ 5,380
Customers - end of period:			
Residential customers	617,039	611,564	5,475
Commercial customers	62,975	62,532	443
Industrial customers	922	906	16
Total number of customers - end of period	680,936	675,002	5,934
Actual degree days	2,659	2,918	
Percent colder than average weather(3)	4 %	14 %	

(1) Regulatory adjustment for income taxes paid is described below.

(2)

Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.

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

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Residential and Commercial Sales

Three months ended June 30, 2012 compared to June 30, 2011:

The primary factors contributing to changes in residential and commercial volumes and operating revenues in the second quarter of this year as compared to the same period last year were:

- sales volumes decreased 17 percent due to weather that was 25 percent warmer than 2011;
- utility operating revenues decreased $56.4 million or 40 percent, primarily due to $34.3 million of credits to customers' bills in June related to the refund of gas cost savings, as well as the effects of warmer weather; and
- utility margin decreased $5.7 million or 10 percent, including weather normalization, which stabilizes margins when weather is warmer or colder than normal and decoupling, which stabilizes margins when average use per customer increases or decreases. The net decrease in margin reflects last year's positive margin contributions from colder weather when the full impact of the weather normalization mechanism was not in effect for the month of May.

Six months ended June 30, 2012 compared to June 30, 2011:

The primary changes that impacted margin from residential and commercial sales for the six months ended June 30, 2012 compared to June 30, 2011 were as follows:

- utility sales volumes were 5 percent lower, primarily reflecting 9 percent warmer weather;
- utility operating revenues decreased $63.0 million or 15 percent primarily due to $34.3 million of credits to customers' bills in June related to the refund of gas cost savings, as well as the effects of warmer weather; and
- utility margin decreased $4.0 million or 2 percent, including weather normalization, which stabilizes margins when weather is warmer or colder than normal and when average use per customer increases or decreases. The decrease in margin reflects the warmer weather compared to last year's very cold weather when the full impact of the mechanisms were not in effect in May.

Industrial Sales and Transportation

Three months ended June 30, 2012 compared to June 30, 2011:

The primary factors that impacted second quarter results from industrial sales and transportation markets were as follows:

- volumes delivered to industrial customers decreased by 1.9 million therms, or less than 2 percent primarily due to one large transportation customer closing their plant during June for maintenance. This closure did not have a significant impact on margin; and
- margin remained flat with only a slight decrease of $0.1 million, or 1 percent.

Industrial customers also received credits totaling $2.6 million on their June bills related to the refund of gas cost savings.

Six months ended June 30, 2012 compared to June 30, 2011:

The primary factors that impacted year-to-date results from industrial sales and transportation markets were as follows:

- volumes delivered to industrial customers increased 2.5 million therms, or 1.1 percent. The volume increase in the period reflects the addition of a few new customers in the forest products segment. In addition, due to the price advantage of natural gas over oil, we are beginning to see asphalt plants converting to natural gas and a trend in other businesses to also convert from legacy oil boilers to natural gas; and
- margin from industrial customers remained relatively flat with only a slight decrease of $0.1 million.

Regulatory Adjustment for Income Taxes Paid

In prior years, Oregon law required the company to annually review the amount of income taxes collected in rates from utility operations and compare it to the amount of taxes the utility paid. In 2011, this law was repealed. We did not recognize any income or expense related to this regulatory adjustment for the three and six months ended June 30, 2012; however, in the second quarter of 2011, we recorded a one-time, pre-tax charge of $7.4 million, including accrued interest. For more information on regulatory income taxes paid, see Results of Operations – Business Segments – Utility Operations – Regulatory Adjustment for Income Taxes Paid in our 2011 Form 10-K.

Other Revenues

Other revenues include miscellaneous fee income and other regulatory adjustments. Other revenues were $1.6 million in the second quarter of 2012, a decrease of $0.5 million over the second quarter of 2011. Other revenues were $3.0 million in the six months ended June 30, 2012, an increase of $0.3 million over the same period of 2011.

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Cost of Gas Sold

Cost of gas sold as reported by the utility includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, production from gas reserves and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the same 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 (see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). In addition, we recently entered into a regulatory agreement where we receive a rate base return on our investment in gas reserves (see Part II, Item 7., "Regulatory Matters-Rate Mechanisms-Purchased Gas Adjustment and Regulatory Matters-Rate Mechanisms-Gas Reserves in the 2011 Form 10-K).

We use natural gas commodity-based hedge contracts (derivative instruments), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage our exposure to rising gas prices. Gains and losses from these financial hedge contracts are generally included in our PGA prices and normally do not impact net income because the hedged prices are reflected in our annual rate changes, subject to a regulatory prudency review. However, hedge contracts entered into after the annual PGA rates are set in Oregon can impact net income because we would be required to share in any gains or losses as compared to the corresponding commodity prices built into rates in the PGA. In Washington, 100 percent of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," and "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," in the 2011 Form 10-K, and Note 12 in this report).

Three months ended June 30, 2012 compared to June 30, 2011:

The following summarizes the major factors that contributed to changes in cost of gas sold for the three months ended June 30, 2012:

- total cost of gas sold decreased $55.6 million, or 62 percent, including the $35.8 million of credits applied to customer billings in June 2012. Excluding the customer credits, total cost of gas decreased $19.8 million or 22 percent, primarily reflecting lower usage due to weather that was 25 percent warmer than the last year;
- average gas cost collected through rates, excluding customer refunds for gas cost savings, decreased 10 percent from 59 cents per therm in 2011 to 53 cents per therm in 2012, primarily reflecting the lower prices that were passed on to customers through the PGA effective November 1, 2011; and
- hedge losses totaling $21.3 million were realized and included in cost of gas sold this quarter, compared to $8.7 million of hedge losses in the same period of 2011. Since the underlying hedge prices were included in our PGA billing rates, these losses did not impact the company's margin or net income.

The effect on operating results from our gas cost incentive sharing mechanism was a margin gain of $0.5 million in the second quarter of 2012, compared to a margin gain of $0.1 million for the second quarter of 2011.

Six months ended June 30, 2012 compared to June 30, 2011:

- total cost of gas sold decreased $66.4 million, or 25 percent, including the $35.8 million of credits applied to customer billings in June 2012. Excluding the customer credits, total cost of gas decreased $30.7 million or 11

percent, primarily reflecting lower usage due to weather that was 9 percent warmer than the same period in 2011;
- average gas cost collected through rates, excluding customer refunds for gas cost savings, decreased from 60 cents per therm in 2011 to 55 cents per therm in 2012, primarily reflecting lower gas prices that were passed on through PGA rate decreases effective November 1, 2011; and
- hedge losses totaling $50.7 million were realized and included in cost of gas sold for the six months ended June 30, 2012, compared to $29.6 million of hedge losses in the same period of 2011. Since the underlying hedge prices were included in our PGA billing rates, these losses did not impact margin or net income.

The amount recorded to pre-tax income from the shareholders' portion of our gas cost incentive sharing mechanism was a margin contribution of $3.1 million in the first half of 2012 compared to $1.1 million in 2011. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above.

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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.

Three months ended June 30, 2012 compared to June 30, 2011:

For the three months ended June 30, 2012, we earned $1.1 million, or 4 cents per share, compared to $1.3 million, or 5 cents per share, for the same period in 2011. The $0.2 million decrease in net income over 2011 is primarily due to higher interest expense from Gill Ranch's $40 million subsidiary senior secured debt, which was issued in the fourth quarter of 2011 and lower market prices for storage, partially offset by improved operating income at Gill Ranch for the second quarter of 2012 compared to 2011. These improved results primarily reflect higher revenues from an increase in contracted capacity and lower than expected power costs.

Six months ended June 30, 2012 compared to June 30, 2011:

For the six months ended June 30, 2012, our gas storage segment earned $1.9 million, or 7 cents per share, compared to $2.0 million, or 8 cents per share, for the same period in 2011. This decrease is primarily due to higher interest expense from Gill Ranch's $40 million subsidiary senior secured debt, which was issued in the fourth quarter of 2011 and lower net operating income from our Mist facility, which was due to lower market prices for storage. In addition, we had lower revenues from third-party asset management services. Partially offsetting these decreases was improved operating income at Gill Ranch primarily reflecting higher revenues from an increase in contracted capacity and lower than expected power costs.

Gas storage margin increased $2.2 million to $14.7 million for the six months ended June 30, 2012. This increase in margin is primarily due to increased revenues from Gill Ranch from higher contracted capacity, partially offset by a decrease in Mist storage firm contract revenue, and third-party asset management revenues.

Business Segments - Other

Our other business segment consists primarily of NNG Financial's investment in KB Pipeline, an equity investment in PGH, which in turn has invested in the Palomar pipeline project, and other miscellaneous non-utility investments and business activities. NNG Financial had total assets of $1.0 million as of both June 30, 2012 and 2011 primarily reflecting a non-controlling interest in the KB Pipeline, which is contracted to serve our utility. Our net equity investment in PGH as of June 30, 2012 and 2011 was $13.5 million and $14.4 million, respectively, with the year-over-year decrease reflecting a $1.3 million write-down taken in 2011. In aggregate, earnings from our other business segment for the six months ended June 30, 2012 and 2011 were net losses of $17 thousand and $0.3 million, respectively. See Note 4 in the 2011 Form 10-K, and Note 4 and Note 11 in this report, for further details on our other business segment and our investment in PGH.

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Consolidated Operations

Operations and Maintenance

Three months ended June 30, 2012 compared to June 30, 2011:

Operations and maintenance expense was $32.1 million in 2012 compared to $30.4 million in 2011 for an increase of $1.8 million or 6 percent. The primary factors contributing to the increase were:

- a $1.2 million increase in utility payroll primarily related to an increase in field service employees; and
- a $0.9 million increase in utility employee benefit expense, primarily related to health care and pension costs. See below for an additional discussion on pension costs.

Partially offsetting the above factors was:

- a $0.2 million decrease in utility bad debt expense.

Six months ended June 30, 2012 compared to June 30, 2011:

Operations and maintenance expense was $66.5 million in 2012 compared to $61.5 million in 2011, for an increase of $5.0 million or 8 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense for the six months ended June 30, 2012 compared to June 30, 2011:

- a $2.5 million increase in utility payroll primarily related to an increase in field service employees;
- a $1.9 million increase in utility employee benefit expense, principally related to health care and pension costs (see below); and
- a $1.8 million increase in utility non-payroll expense including higher costs for new employee training, expenses related to the Oregon general rate case, higher costs for information technology system maintenance and other customer service cost increases.

Partially offsetting the above factors were:

- a $0.4 million reduction in operating expense in our gas storage segment primarily due to higher start-up costs for Gill Ranch in the first six months of 2011; and
- a $0.2 million decrease in utility bad debt expense.

Our bad debt expense decreased in the second quarter of 2012 partly due to the positive impact of customer refunds on delinquent balances as of June 30, 2012. Our bad debt expense as a percent of revenues was 0.22 percent for the twelve months ended June 30, 2012, compared to 0.24 percent for the same period last year. Our bad debt expense results over the past few years have been favorable despite challenging economic conditions. We believe credit risks are still elevated due to the continuing weak economy and high unemployment rates, but we expect our bad debt expense ratio over the long term to remain below 0.5 percent of revenues.

Our accounting expense for pension costs increased fairly significantly in 2012 largely due to lower interest rates; however, the OPUC approved a deferral of NW Natural's utility pension costs for amounts in excess of pension costs currently recovered in rates. The pension cost deferral is recorded to a regulatory balancing account, which reduces operations and maintenance expense. For the three and six months ended June 30, 2012, we deferred pension expenses totaling $2.1 million and $4.2 million, respectively, and $1.3 million and $2.7 million for the same periods last year (see Note 8). 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 customers. For further explanation of the pension balancing account, see “Regulatory Matters—Rate Mechanisms—Pension Deferral,” above.

General Taxes

Three months ended June 30, 2012 compared to June 30, 2011:

General taxes increased $0.8 million, or 11 percent, in the three months ended June 30, 2012 over the same period in 2011, primarily due to a $0.5 increase in property taxes at Gill Ranch.

Six months ended June 30, 2012 compared to June 30, 2011:

General taxes increased $1.4 million in the first six months of 2012 compared to 2011. This increase was primarily due to a $1.0 increase in property taxes at Gill Ranch because of capital investments added to our assessed tax base for 2012.

Depreciation and Amortization

Depreciation and amortization expense increased by $0.6 million, or 3 percent for the three months ended June 30, 2012, compared to the same period in 2011. For the six months ended June 30, 2011, depreciation and amortization expense increased by $1.2 million, or 3 percent, as compared to the same period in 2011. The increased expense in 2012 was primarily related to higher depreciation at the utility and Gill Ranch because of plant asset additions.

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Other Income and Expense – Net

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

Thousands	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Gains from company-owned life insurance	$608	$694	$1,392	$1,199
Interest income	89	23	105	30
Income from equity investments	2	(353)	1	(353)
Net interest on deferred regulatory accounts	835	1,501	1,840	3,015
Gain (loss) on sale of investments	-	-	-	(96)
Other non-operating	(613)	(743)	(1,412)	(1,459)
Total other income and expense - net	$921	$1,122	$	