NORTHWEST NATURAL GAS CO
Form 10-Q
November 06, 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 September 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 [ ]	Smaller reporting company [ ]

(Do not check if a smaller reporting company)

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

At October 26, 2012, 26,874,412 shares of the registrant’s Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended September 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)

	Three Months Ended September 30,		Nine Months Ended September 30,	
Thousands, except per share amounts	2012	2011	2012	2011
Operating revenues:				
Gross operating revenues	$89,756	$93,313	$513,819	$577,598
Less: Cost of sales	37,586	43,133	241,869	313,880
Revenue taxes	2,255	2,397	12,688	14,195
Net operating revenues	49,915	47,783	259,262	249,523
Operating expenses:				
Operations and maintenance	28,957	28,372	95,497	89,918
General taxes	7,473	7,514	23,726	22,338
Depreciation and amortization	18,281	17,449	54,330	52,304
Total operating expenses	54,711	53,335	173,553	164,560
Income (loss) from operations	(4,796)	(5,552)	85,709	84,963
Other income and expense - net	1,710	1,781	3,636	4,117
Interest expense - net	10,508	10,241	32,163	30,956
Income (loss) before income taxes	(13,594)	(14,012)	57,182	58,124
Income tax expense (benefit)	(3,036)	(5,700)	25,724	23,470
Net income (loss)	(10,558)	(8,312)	31,458	34,654
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $108 and $95 for the three months and $325 and $287 for the nine months ended September 30, 2012 and 2011, respectively	167	146	499	438
Comprehensive income (loss)	$(10,391)	$(8,166)	$31,957	$35,092
Average common shares outstanding:				
Basic	26,847	26,686	26,813	26,676
Diluted	26,847	26,686	26,902	26,730
Earnings (loss) per share of common stock:				
Basic	$(0.39)	$(0.31)	$1.17	$1.30
Diluted	$(0.39)	$(0.31)	$1.17	$1.30
Dividends declared per share of common stock	$0.445	$0.435	$1.335	$1.305

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets
(Unaudited)

Thousands	September 30, 2012	September 30, 2011	December 31, 2011
Assets:			
Current assets:			
Cash and cash equivalents	$5,718	$25,862	$5,833
Accounts receivable	23,382	25,628	77,449
Accrued unbilled revenue	11,184	14,287	61,925
Allowance for uncollectible accounts	(1,985)	(1,733)	(2,895)
Regulatory assets	53,891	76,734	94,673
Derivative instruments	6,771	3,932	2,853
Inventories	73,188	83,581	74,363
Gas reserves	13,140	2,366	4,463
Income taxes receivable	1,787	5,019	7,045
Other current assets	10,825	14,871	22,980
Total current assets	197,901	250,547	348,689
Non-current assets:			
Property, plant and equipment	2,755,729	2,632,498	2,661,102
Less: Accumulated depreciation	798,510	756,592	767,226
Total property, plant and equipment - net	1,957,219	1,875,906	1,893,876
Gas reserves	75,925	28,125	47,451
Regulatory assets	367,692	328,757	371,392
Derivative instruments	5,608	227	—
Other investments	67,333	69,022	68,263
Restricted cash	4,000	—	4,000
Other non-current assets	14,690	15,256	12,903
Total non-current assets	2,492,467	2,317,293	2,397,885
Total assets	$2,690,368	$2,567,840	$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	September 30, 2012	September 30, 2011	December 31, 2011
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,866, 26,703, and 26,756 at September 30, 2012 and 2011 and December 31, 2011, respectively	$355,276	$346,197	$348,383
Retained earnings	369,584	356,574	373,905
Accumulated other comprehensive loss	(7,301)	(6,166)	(7,800)
Total common stock equity	717,559	696,605	714,488
Long-term debt	641,700	601,700	641,700
Total capitalization	1,359,259	1,298,305	1,356,188
Current liabilities:			
Short-term debt	175,800	181,200	141,600
Current maturities of long-term debt	—	40,000	40,000
Accounts payable	61,327	50,117	86,300
Taxes accrued	10,269	11,117	10,747
Interest accrued	10,593	11,321	5,857
Regulatory liabilities	24,810	28,593	31,046
Derivative instruments	17,156	46,651	57,317
Other current liabilities	45,425	33,609	41,597
Total current liabilities	345,380	402,608	414,464
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	430,885	394,217	413,209
Regulatory liabilities	288,097	266,907	278,382
Pension and other postretirement benefit liabilities	182,069	129,669	201,530
Derivative instruments	615	7,429	6,536
Other non-current liabilities	84,063	68,705	76,265
Total deferred credits and other non-current liabilities	985,729	866,927	975,922
Commitments and contingencies (see Note 13)			
Total capitalization and liabilities	$2,690,368	$2,567,840	$2,746,574

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows
(Unaudited)

Thousands	Nine Months Ended September 30, 2012	2011
Operating activities:		
Net income	$31,458	$34,654
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	54,330	52,304
Non-cash expenses related to qualified defined benefit pension plans	4,334	5,491
Contributions to qualified defined benefit pension plans	(23,500)	(19,245)
Deferred environmental expenditures - net of recoveries	(6,500)	(7,018)
Other	2,612	(615)
Changes in assets and liabilities:		
Receivables	106,620	92,840
Inventories	1,175	(3,196)
Taxes accrued	4,780	36,585
Accounts payable	(24,888)	(33,369)
Interest accrued	4,736	6,139
Deferred gas costs	(15,406)	370
Deferred tax liabilities	24,503	22,908
Other - net	13,808	3,440
Cash provided by operating activities	178,062	191,288
Investing activities:		
Capital expenditures	(100,880)	(70,036)
Utility gas reserves	(41,775)	(30,917)
Restricted cash	—	924
Other	107	(192)
Cash used in investing activities	(142,548)	(100,221)
Financing activities:		
Common stock issued - net, including common stock expense	4,858	1,320
Long-term debt issued	—	50,000
Long-term debt redeemed	(40,000)	(10,000)
Change in short-term debt	34,200	(76,235)
Cash dividend payments on common stock	(35,779)	(34,807)
Other	1,092	1,060
Cash used in financing activities	(35,629)	(68,662)
Increase (decrease) in cash and cash equivalents	(115)	22,405
Cash and cash equivalents - beginning of period	5,833	3,457
Cash and cash equivalents - end of period	$5,718	$25,862
Supplemental disclosure of cash flow information:		
Interest paid	$27,427	$24,817
Income taxes paid	$2,333	$1,522

See Notes to Consolidated Financial Statements.

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 nine months ended September 30, 2012. The following are current updates to certain critical accounting policy estimates and accounting standards in general. See Note 14 for disclosures of subsequent events that occurred after September 30, 2012 but prior to issuance of this report.

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 September 30, 2012 and 2011 and at December 31, 2011, the amounts deferred as regulatory assets and liabilities were as follows:

Regulatory Assets

Thousands	September 30, 2012	September 30, 2011	December 31, 2011
Current:			
Unrealized loss on derivatives(1)	$17,156	$46,651	$57,317
Pension and other postretirement benefit liabilities(2)	15,491	10,988	15,491
Other(3)	21,244	19,095	21,865
Total current	$53,891	$76,734	$94,673
Non-current:			
Unrealized loss on derivatives(1)	$615	$7,429	$6,536
Pension balancing(2)	13,134	3,989	6,008
Income tax asset	58,437	70,241	65,264
Pension and other postretirement benefit liabilities(2)	158,894	110,007	170,512
Environmental costs(4)	128,173	122,454	105,670
Other(3)	8,439	14,637	17,402
Total non-current	$367,692	$328,757	$371,392

Regulatory Liabilities

Thousands	September 30, 2012	September 30, 2011	December 31, 2011
Current:			
Gas costs	$10,069	$16,991	$17,994
Unrealized gain on derivatives(1)	6,771	3,932	2,853
Other(3)	7,970	7,670	10,199
Total current	$24,810	$28,593	$31,046
Non-current:			
Gas costs	$596	$1,250	$8,420
Unrealized gain on derivatives(1)	5,608	227	—
Accrued asset removal costs	278,897	263,123	267,355
Other(3)	2,996	2,307	2,607
Total non-current	$288,097	$266,907	$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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PART I. FINANCIAL INFORMATION

New Accounting Standards

Adopted Standards

There were no new accounting standards adopted during the third quarter of 2012.

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 do not expect this standard to have a material effect 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 September 30,		Nine Months Ended September 30,	
Thousands, except per share amounts	2012	2011	2012	2011
Net income	$(10,558)	$(8,312)	$31,458	$34,654
Average common shares outstanding - basic	26,847	26,686	26,813	26,676
Additional shares for stock-based compensation plans outstanding (See Note 6)	—	—	89	54
Average common shares outstanding - diluted	26,847	26,686	26,902	26,730
Earnings per share of common stock - basic	$(0.39)	$(0.31)	$1.17	$1.30
Earnings per share of common stock - diluted	$(0.39)	$(0.31)	$1.17	$1.30
Anti-dilutive shares excluded from net income per diluted common share calculation	107	63	—	3

4. Segment Information

We operate in two primary reportable business segments, which we refer to as “utility” and “gas storage.” We refer to our gas storage and other business segments as “non-utility.” Gas storage segment includes: NWN Gas Storage; Gill Ranch; non-utility portions of our underground storage facility in Oregon (Mist); and revenues from third-party asset management services. Other investments and business activities, which we refer to as “other”, primarily includes NNG Financial and our equity investment in PGH. 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 nine months ended September 30, 2012 and 2011:

	Three Months Ended Three Months Ended September 30,			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2012				
Net operating revenues	$42,331	$7,544	$40	$49,915
Depreciation and amortization	16,661	1,620	—	18,281
Income (loss) from operations	(8,439)	3,624	19	(4,796)
Net income (loss)	(11,853)	1,255	40	(10,558)
2011				
Net operating revenues	$41,034	$6,710	$39	$47,783
Depreciation and amortization	15,875	1,574	—	17,449
Income (loss) from operations	(8,029)	2,458	19	(5,552)
Net income (loss)	(9,518)	1,160	46	(8,312)
	Six Months Ended Nine Months Ended September 30,			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2012				
Net operating revenues	$236,921	$22,219	$122	$259,262
Depreciation and amortization	49,477	4,853	—	54,330
Income from operations	76,072	9,567	70	85,709
Net income	28,250	3,185	23	31,458
Total assets at September 30, 2012	2,386,879	287,687	15,802	2,690,368
2011				
Net operating revenues	$230,244	$19,211	$68	$249,523
Depreciation and amortization	47,735	4,569	—	52,304
Income from operations	77,762	7,191	10	84,963
Net income (loss)	31,702	3,163	(211)	34,654
Total assets at September 30, 2011	2,291,531	253,478	22,831	2,567,840
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 under which we may purchase our common 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 nine months ended September 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.

Shareholders approved the amended LTIP and authorized an additional 250,000 shares for the plan. A variety of equity vehicles may be granted under the LTIP. Together 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. During the nine months ended September 30, 2012, the company granted 22,220 RSUs under the LTIP with grant date fair values ranging from $48.00 to $48.25 per share. 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.

Restated Stock Option Plan

As of September 30, 2012, there was $0.6 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, outstanding options may still be exercised through their expiration dates. Any new grants of stock options would be made under the LTIP. No new stock options were granted in the nine months ended September 30, 2012.

7. Cost and Fair Value of Debt

Cost and Fair Value of Short-Term Debt

Our short-term debt at September 30, 2012 consisted of commercial paper notes payable with a maximum maturity of 254 days, an average maturity of 88 days and an outstanding balance of $175.8 million. The carrying cost of our commercial paper approximates a fair value, using Level 2 inputs, due to the short-term nature of the notes. See description of fair value hierarchy in Note 2 in our 2011 Form 10-K.

Cost and Fair Value of Long-Term Debt

Our utility's long-term debt consists of $601.7 million of first mortgage bonds 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 first mortgage bonds. In July of 2012, we entered into a bond purchase agreement to sell $50 million of first mortgage bonds with a coupon rate of 4.00 percent and a 30-year maturity, which closed on October 30, 2012 (see Note 14). The proceeds of the issuance will be used to reduce short-term debt and for other general corporate purposes.

Our gas storage segment's long-term debt consists of $40 million of senior secured notes with a maturity date of November 30, 2016. These senior secured notes consist of $20 million fixed rate notes, which have an interest rate of 7.75 percent and of $20 million variable rate notes, which currently have an interest rate of 7.00 percent. The notes are secured by our 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.

As our outstanding debt does not trade in active markets, we estimated the the fair value of our outstanding long-term debt using interest rates of other companies' outstanding debt issuances that actively trade in public markets and have similar credit ratings, terms and remaining maturities to our debt. These valuations are based on Level 2 inputs as defined in the fair value hierarchy (see description of fair value hierarchy in Note 2 in our 2011 Form 10-K).

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	September 30,		December 31,
Thousands	2012	2011	2011
Carrying amount	$641,700	$641,700	$681,700
Estimated fair value	$786,496	$774,186	$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 Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2012	2011	2012	2011
Service cost	$2,130	$1,839	$177	$168
Interest cost	4,303	4,503	314	344
Expected return on plan assets	(4,637)	(4,455)	—	—
Amortization of net actuarial loss	3,844	2,683	103	68
Amortization of prior service costs	48	88	50	50
Amortization of transition obligations	—	—	103	103
Net periodic benefit cost	5,688	4,658	747	733
Amount allocated to construction	(1,676)	(1,279)	(252)	(234)
Amount deferred to regulatory balancing account(1)	(2,111)	(1,330)	—	—
Net amount charged to expense	$1,901	$2,049	$495	$499

	Six Months Ended Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2012	2011	2012	2011
Service cost	$6,390	$5,638	$531	$504
Interest cost	12,911	13,556	943	1,031
Expected return on plan assets	(13,914)	(13,367)	—	—
Amortization of net actuarial loss	11,531	8,067	309	204
Amortization of prior service costs	146	264	148	148
Amortization of transition obligations	—	—	309	309
Net periodic benefit cost	17,064	14,158	2,240	2,196
Amount allocated to construction	(4,522)	(3,765)	(681)	(689)
Amount deferred to regulatory balancing account(1)	(6,273)	(3,989)	—	—
Net amount charged to expense	$6,269	$6,404	$1,559	$1,507

[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 net periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility’s authorized rate of return. See "Regulatory Accounting" in Note 2.

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Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

In the nine months ended September 30, 2012, we made cash contributions totaling $23.5 million to our qualified defined benefit pension plans. In July 2012, Congress passed the "Moving Ahead for Progress in the 21st Century Act" (MAP-21), which among other things includes a method of stabilizing interest rate assumptions and has the effect of reducing short-term minimum funding requirements but increasing operational costs of running a pension plan. We are evaluating the impact of MAP-21 on contribution requirements to our qualified pension plans and will update our funding estimates in future filings.

Multiemployer Pension Plan

In addition to the company-sponsored defined benefit pension plans referred to above, we contribute to a defined benefit 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). The cost of this plan is in addition to pension expense presented in the table above. Our contributions to the Western States Plan amounted to $0.3 million for the nine months ended September 30, 2012 and 2011. 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.

Defined Contribution Plan

The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Our contributions to this plan totaled $1.7 million and $1.8 million for the nine months ended September 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 nine months ended September 30, 2012 and 2011 varied from the combined federal and state statutory tax rates principally due to the following:

	September 30,			
	2012		2011	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.7	%	4.5	%
Amortization of investment and energy tax credits	(0.3	)%	(0.4	)%
Differences required to be flowed-through by regulatory commissions	1.4	%	1.5	%
Gains on company and trust-owned life insurance	(1.2	)%	(0.9	)%
One-time state tax adjustment, net of federal benefit	4.7	%	—	%
Other - net	0.7	%	0.7	%
Effective income tax rate	45.0	%	40.4	%

The increase in the effective income tax rate for the nine months ended September 30, 2012 compared to the same period in 2011 was primarily due to a one-time, after-tax charge of $2.7 million in the third quarter of 2012 related to the OPUC's rate case order that the Company cannot recover deferred amounts resulting from the 2009 Oregon tax rate change. See Note 14 in this filing for more information on the one-time, tax charge and 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
PART I. FINANCIAL INFORMATION

10. Property, Plant and Equipment

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

	September 30,		December 31,
Thousands	2012	2011	2011
Utility plant in service	$2,399,600	$2,296,788	$2,323,467
Utility construction work in progress	53,017	36,459	36,051
Less: Accumulated depreciation	776,812	740,378	749,603
Utility plant-net	1,675,805	1,592,869	1,609,915
Non-utility plant in service	296,486	290,075	293,205
Non-utility construction work in progress	6,626	9,176	8,379
Less: Accumulated depreciation	21,698	16,214	17,623
Non-utility plant-net	281,414	283,037	283,961
Total property, plant and equipment	$1,957,219	$1,875,906	$1,893,876

11. Gas Reserves and Other Investments

Our gas reserves are stated at cost, net of 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 cash surrender 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. These agreements are intended to provide long-term gas price protection for our utility customers. Encana began drilling in 2011 under these agreements, and we are currently producing gas from our interests in these gas fields. Our cost of gas, including a carrying cost for the net rate base investment, are part of our annual Oregon Purchased Gas Adjustment (PGA) filing, which allows us to recover our costs through customer rates in a manner previously approved by the OPUC. This transaction accounted for approximately 4% of our gas supplies for the nine months ended September 30, 2012. The following table outlines our net investment at September 30, 2012 and 2011 and December 31, 2011:

	September 30,		December 31,
Thousands	2012	2011	2011
Gas reserves, current	$13,140	$2,366	$4,463
Gas reserves, non-current	81,692	28,551	48,597
Less: Accumulated amortization	5,767	426	1,146
Total gas reserves	89,065	30,491	51,914
Less: Deferred taxes on gas reserves	23,940	10,090	15,630
Net investment in gas reserves	$65,125	$20,401	$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 the asset is included as gas reserves on our balance sheet. Our maximum loss exposure related to the VIE is limited to our investment balance.

Equity Method Investments

PGH is a development stage VIE. 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 September 30, 2012, there were no changes to our VIE analysis and, as such, we continue to report Palomar under equity method accounting based on the determination that we are not the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations due to the fact that we have a 50 percent share and there are no stipulations that allow disproportionate influence over the entity. Our investment in PGH and Palomar are included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50 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 $13.4 million at September 30, 2012. Palomar is continuing to work on development of commercial support for the project and expects to file a new Federal Energy Regulatory Commission (FERC) certification application to reflect a revised scope based on regional needs for the proposed pipeline. 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 as of September 30, 2012 based on the current amount of our equity investment net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required. See Note 12 in our 2011 Form 10-K for more detail on Palomar and our annual impairment analysis.

12. Derivative Instruments

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

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of 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 nine months ended September 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.

Thousands	Three Months Ended September 30, 2012 Natural gas commodity(1)	Foreign currency (2)	September 30, 2011 Natural gas commodity(1)	Foreign currency (2)
Cost of sales	$22,558	$—	$(18,987)	$—
Other comprehensive income (loss)	—	273	—	(1,221)
Less:				
Amounts deferred to regulatory accounts on balance sheet	(22,558)	(273)	18,987	1,221
Total impact on earnings	$—	$—	$—	$—

	Nine Months Ended			
	September 30, 2012		September 30, 2011	
Thousands	Natural gas commodity[1]	Foreign currency [2]	Natural gas commodity[1]	Foreign currency [2]
Cost of sales	$(5,556)	$—	$(49,106)	$—
Other comprehensive income (loss)	—	162	—	(815)
Less:				
Amounts deferred to regulatory accounts on balance sheet	5,556	(162)	49,106	815
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 September 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 portfolio 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 $5.4 million at September 30, 2012, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$—	$—	$—	$—	$585
Without Adequate Assurance Calls	$—	$—	$—	$—	$522

In the three and nine months ended September 30, 2012, we realized net losses of $12.7 million and $63.3 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 $6.6 million and $36.2 million, respectively, for the three and nine months ended September 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 September 30, 2012. As of September 30, 2012 and 2011 and December 31, 2011, the fair value was $5.4 million, $49.9 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 nine months ended September 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 based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives. 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 (RI) 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 will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. 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.

Other Portland Harbor. 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 September 30, 2012, we have an accrued liability of $4.4 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 September 30, 2012 for the Gasco upland site is $8.7 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. We submitted our final design for source control in January 2012. ODEQ approved construction of the designed system but subsequently requested another component for source control outside the original design. Construction began in October 2012. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding the effectiveness of the source control system, we have estimated a range of liability between $16.8 million and $30 million, for which we have recorded an accrued liability of $16.8 million at September 30, 2012, 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. We are uncertain about the range due to potential additional ODEQ requirements and actions needed to meet those requirements, including uncertainty about how to meet the agreed standards set by ODEQ subsequent to the initial testing of the system and as part of the final remedy for the unpland portion of the Gasco site.

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 September 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 September 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 LWG 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 LWG 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 September 30, 2012, we have an estimated liability accrued of $1.4 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 September 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	September 30, 2012	September 30, 2011	December 31, 2011	September 30, 2012	September 30, 2011	December 31, 2011
Portland Harbor site:						
Gasco/Siltronic Sediments	$1,748	$1,490	$1,614	$43,628	$30,604	$35,797
Other Portland Harbor	1,188	2,174	1,893	3,186	5,122	7,066
Gasco upland site	18,018	8,899	14,092	7,453	7,447	8,900
Siltronic upland site	511	721	887	592	114	128
Central Service Center site	100	5	—	445	530	495
Front Street site	942	—	1,697	452	765	—
Oregon Steel Mills	—	—	—	185	129	120
Total	$22,507	$13,289	$20,183	$55,941	$44,711	$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. In October 2012, the OPUC authorized a new mechanism for environmental cost recovery through rates. This Site Remediation Recovery Mechanism (SRRM) allows the Company to recover prudently incurred environmental site remediation costs. The rate case also establishes an earnings review related to this mechanism, which will be further defined in a future proceeding. The ultimate amounts we recover under SRRM will depend upon future insurance recoveries, future expenditures, prudency reviews, and the impacts of any earnings review the OPUC may adopt in a subsequent proceeding.

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 paid $69.6 million for environmental costs, including legal, investigation, monitoring and remediation costs, of which $4.9 million was paid and expensed prior to regulatory deferral order approval. At September 30, 2012, we had a regulatory asset of $128.2 million, which represents those amounts accrued, paid subsequent to regulatory deferral, and interest on those projects.

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.

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 Events

Commission Decision on Oregon General Rate Case

In October 2012, the OPUC authorized an annual Oregon revenue increase of $8.7 million, equivalent to a rate increase of 1.2 percent, effective November 1, 2012. This annual increase included an authorized return on equity of 9.5 percent and an overall rate of return on rate base of 7.78 percent, with a capital structure of 50 percent equity and 50 percent long-term debt. This increase includes the recovery of amounts that had previously been deferred through the company's decoupling mechanism of about $15 million. As a result, the overall effect on the Company is a decline in net operating revenues (utility margin) of approximately $6 million on an annualized basis. In addition to our decoupling mechanism, the OPUC also approved the retention of our weather normalization mechanism. Our system integrity program was extended for two years. They also authorized a SRRM that allows the Company to recover prudently incurred environmental site remediation costs, with a separate earnings review which will be further defined in a future proceeding. The OPUC denied recovery of deferred amounts that represent the increase in deferred income taxes caused by the 2009 Oregon tax rate change, resulting in a one-time, after-tax charge of $2.7 million in the third quarter of 2012.

The OPUC deferred various items for future resolution in separate proceedings including the Commission's review of the Company's recovery of its working gas inventory carrying costs, the decision regarding whether prepaid pension asset should be included in rate base, and the Commission's review of the Company's revenue-sharing arrangement on its interstate storage activities.

Issuance of Long-Term Debt

In July 2012, we signed a bond purchase agreement with investors which closed on October 30, 2012, whereby we issued $50 million of NW Natural first mortgage bonds with a coupon rate of 4.00 percent and a 30-year maturity. The proceeds of the issuance will 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 nine months ended September 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 nine 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 gas storage businesses (gas storage) and other business segments. Our gas storage segment includes NWN Gas Storage, Gill Ranch, non-utility portions of our underground storage facility in Oregon (Mist), and revenues from third-party asset management services. 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

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

- Consolidated net loss of $10.6 million or 39 cents per share in 2012, compared to a net loss of $8.3 million or 31 cents per share in 2011;
- Net loss from utility operations increased $2.3 million to $11.9 million in 2012, which included a one-time, after-tax charge of $2.7 million related to the general rate case;
- Net income from gas storage operations increased $0.1 million, from $1.2 million in 2011 to $1.3 million in 2012;
- Cash flow from operating activities decreased $13.2 million, from $191.3 million in 2011 to $178.1 million in 2012, which included a $39 million refund credited to customers for their share of the current year's gas cost savings; and
- Utility customer count increased by approximately 6,900 over the last 12 months, for an annual growth rate of 1.0 percent compared to 0.8 percent a year ago.

Issues, Challenges and Performance Measures

Economic environment. Continued weakness in the local, national and global economies have impacted utility customer growth, business demand for natural gas and market prices for gas storage. Our utility's annual customer growth rate was 1.0 percent at September 30, 2012, as compared to 0.9 percent at June 30, 2012 and 0.8 percent at September 30, 2011. The local economy is showing signs of a slow recovery, with unemployment rates in Oregon and southwest Washington declining from 2011 to 2012 and industrial customers adding natural gas equipment in certain market sectors. 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.

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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 continuation of low and stable gas prices in the future depends on a combination of supply and demand factors as well as 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, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and reduce price volatility for customers. These lower gas prices, coupled with our focus on customer service and cost-effective energy efficiency programs, help strengthen natural gas' competitive advantage over other energy sources in our key markets.

We typically hedge gas prices for approximately 75 percent of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. At the beginning of the November 1, 2011 – October 31, 2012 gas contract year, we were 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 where we buy at pre-determined prices based on the Company's weighted average cost of gas, and gas production from gas reserves we invested in with Encana Oil & Gas (USA) Inc. (Encana). Our investment in gas reserves with Encana began in 2011. 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.

In addition to the amount hedged for the current gas contract year, we estimate our hedge levels at 72 percent for the upcoming 2012-13 gas year as of September 30, 2012. We have also entered into gas reserve purchases and financial hedge transactions to cover periods 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, storage contracts with third parties, or storage recall by the utility. We expect recovery of our utility storage costs, including demand charges and other operating costs, through the 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 finding 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 actions. In our general rate case, the OPUC approved recovery of costs from environmental site remediation subject to certain conditions as noted in "Results of Operations—Regulatory Matters—Rate Mechanisms" below. We pursue recovery from insurance policies and seek recovery from customers only for amounts not recovered from insurance. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage these costs, demonstrate that costs were prudently incurred, and the impact of any earnings review the OPUC may adopt in a subsequent proceeding. Recovery may vary from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. See Note 13 in this report and Note 15 in our 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;

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utility return on equity; utility customer satisfaction ratings; utility margin; utility capital and operations and maintenance expense per customer; and earnings before interest, taxes, depreciation and amortization (EBITDA).

Strategic Opportunities

Safety, reliability and service. To optimally respond to new federal pipeline safety legislation and system integrity 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 have several ongoing initiatives designed to improve the quality and integrity of our pipeline infrastructure, and to upgrade several facilities to enhance business continuity, employee training and safety, productivity and energy efficiency. We are committed to continued improvement in operational effectiveness and capitalizing on our competitive position and service quality.

Gas storage. 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 interest in the 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 lower gas prices to increase demand for natural gas because lower pricing provides a competitive advantage over alternative energy sources, such as switching coal plants 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. 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, but with no further expansion of our gas transmission pipeline, of which we would have the rights to an additional 5 Bcf or ultimately 50 percent of the total capacity.

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. Earlier this year, 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 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.

As discussed above, we continue to evaluate future storage expansion at Gill Ranch and Mist; however, we do not currently have a set timeline for these developments. We believe the earliest timeframe for completing the next Mist expansion is 2016, and no timeline is currently set for Gill Ranch. In the meantime, we expect to continue working on preliminary design and scope of the next Mist 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 to better serve our utility customers as well as the growing natural gas markets in Oregon and other parts of the Pacific Northwest.

This proposed pipeline would be subject to regulation by the Federal Energy Regulatory Commission (FERC). Palomar intends to file a new application after it has conducted a new open season to obtain specific commercial support for the pipeline. See Part II, Item 7., “2012 Outlook—Strategic Opportunities,” in our 2011 Form 10-K.

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Utility gas reserves. In addition to hedging gas prices with financial swap and option contracts, we entered into an agreement with Encana in 2011 to develop physical gas supplies to hedge a portion of our utility customers' requirements over 30 years. During the first 10 years, we forecast the volumes of gas under the Encana agreement will hedge 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. Encana is the operator, and we pay our proportionate share of the operating costs. Currently, the Encana transaction is expected to hedge approximately 8 percent of our utility gas supply for the 2012-13 gas year. We also continue to evaluate additional investments in gas reserves as part of our gas hedging strategy. 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 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.

Consolidated Earnings and Dividends

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

For the three months ended September 30, 2012, we reported a net loss of $10.6 million, or 39 cents per share, compared to a net loss of $8.3 million, or 31 cents per share, for the same period last year.

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

- a $2.7 million decrease in income tax benefits primarily due to a one-time charge related to the Oregon general rate case;
- a $0.8 million increase in depreciation and amortization expenses primarily due to a higher level of investment in utility property, plant and equipment; and
- a $0.6 million increase in operations and maintenance expense primarily due to increases in utility payroll and utility non-payroll expense including higher costs for safety enhancements, business development, information technology system maintenance and other customer service cost increases, partially offset by decreases in employee incentive compensation.

Partially offsetting the above factors was:

- a $1.3 million increase in utility margin primarily due to an increase in revenues related to customer growth, an increase in revenues related to our gas cost incentive sharing mechanism, and a decrease in revenue sharing with customers from our annual earnings test accrual.

Nine months ended September 30, 2012 compared to September 30, 2011:

Net income was $31.5 million, or $1.17 per share, for the nine months ended September 30, 2012, compared to $34.7 million, or $1.30 per share, for the same period last year.

The primary factors contributing to decreased year-to-date net income were:

- a $5.6 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 $2.7 million one-time, after-tax tax charge related to the Oregon general rate case.
- a $2.0 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;
- a $1.4 million increase in general taxes primarily due to increased property values and associated taxes at Gill Ranch; and
- a $1.2 million increase in interest expense primarily due to the new debt issuance at Gill Ranch late in 2011.

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Partially offsetting the above factors were:

- a $6.7 million increase in utility margin primarily due to a one-time, pre-tax charge of $7.4 million in 2011 related to a utility tax law change in Oregon, and an increase of $2.2 million in revenues related to our gas cost incentive sharing mechanism, partially offset by a decrease in utility margin from the effects of warmer weather in 2012 compared to 2011; and
- a $2.4 million increase in gas storage operating income primarily attributable to revenue increases from Gill Ranch from additional contracted storage capacity.

Dividends paid on our common stock were 44.5 cents per share in the third quarter of 2012, compared to 43.5 cents per share in the third quarter of 2011. The Board of Directors declared a quarterly dividend on our common stock of 45.5 cents per share, payable on November 15, 2012, to shareholders of record on October 31, 2012. The current indicated annual dividend rate is $1.82 per share.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (U.S. 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), except as indicated below under regulatory cost recovery and pension contributions.

Regulatory Cost Recovery

In the Oregon general rate case, the OPUC ruled that we cannot recover deferred amounts that represent the increase in deferred income taxes caused by the 2009 Oregon tax rate change. As a result, we have recognized a one time, after tax charge of $2.7 million in the quarter.

Pension Contributions

In July 2012, President Obama signed into law the Moving Ahead for Progress in the 21st Century Act (MAP-21 Act). This legislation changes several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases operational costs of running a pension plan. Prior to the

MAP-21 Act, we were using interest rates based on a 24-month average yield of investment grade corporate bonds (also referred to as “segment rate”) to calculate minimum contribution requirements. The MAP-21 Act establishes a new minimum and maximum corridor for segment rates based on a 25-year average of bond yields, which is to be used in calculating contribution requirements. For 2013, the new corridor will be set at no less than 85 percent and no more than 115 percent of the corresponding 25-year average segment rate. In 2014, the corridor widens to 80 percent to 120 percent of the 25-year average, and the corridor continues to widen by 5 percent each year thereafter until reaching 70 percent to 130 percent. Under current market conditions, we estimate the segment rate for the 2013 Plan Year will increase from approximately 4.90 percent to 6.25 percent, and this 1.35 percent increase in interest rates would reduce our minimum contribution requirement by approximately $15 million, from roughly $26 million under the unadjusted 24-month segment rate to roughly $11 million under the adjusted 24-month segment rate using the 85 to 115 percent corridor.

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We are continuing to evaluate the impact of MAP-21 on contribution requirements and will update our funding and pension expense estimates in future filings.

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. Earnings and cash flows from utility operations are largely determined by rates set in rate cases and other proceedings in Oregon and Washington, but will also be affected by the economies in Oregon and Washington, by the pace of customer growth in the residential and commercial markets, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets. See Oregon General Rate Case below.

Gas Storage. Our gas storage business is subject to regulation with respect to, among other matters, issuance of securities and systems of accounts set by the OPUC, California Public Utilities Commission (CPUC), and FERC. The OPUC and FERC regulate 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. Our gas storage revenues were derived from approximately 55 percent OPUC and FERC approved cost-based rates and 45 percent CPUC approved market-based rates for the nine months ended September 30, 2012. This compared to 66 percent OPUC and FERC approved rates and 34 percent CPUC approved rates for the same period in 2011.

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

Oregon General Rate Case

In December 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 filing requested an authorized overall rate of return on rate base 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. The overall amount and percent of the requested rate increase included an estimated $15.1 million increase already included in current rates for the cumulative effect of customer conservation covered by NW Natural's decoupling mechanism, which reflects declining use per customer since 2003. This decision essentially resets the baseline against which changes in use per customer are measured under the Company's decoupling mechanism, which has been in place since 2003. Our requested increase also included costs related to pension contributions, and additional utility services. In its filing, the Company also requested the establishment of a rate recovery mechanism for deferred costs related to our environmental liabilities.

In October 2012, we received a preliminary order concerning the Company's general rate case, which, together with various stipulations that were settled in advance of the order, resulted in the following items being approved by the Commission effective November 1, 2012:

- An annual Oregon jurisdictional revenue increase of $8.7 million, equivalent to a rate increase of 1.2 percent. This increase includes the recovery of amounts that had previously been deferred through the company's decoupling mechanism of about $15 million. As a result, the overall effect on the Company is a decline in net operating revenues (utility margin) of approximately $6 million on an annualized basis;
- An overall rate of return on rate base of 7.78 percent and an authorized ROE of 9.5 percent, with a capital structure of 50 percent common equity and 50 percent long-term debt;

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- The retention of our current decoupling and weather normalization mechanisms. See Conservation Tariff below and Part II, Item 7., “Results of Operations-Regulatory Matters-Rate Mechanisms,” in the 2011 Form 10-K for details on these programs;
- A two-year extension of our cap-ex tracking mechanism to recover capital costs related to system integrity program. See Part II, Item 7., “Results of Operations-Regulatory Matters-Rate Mechanisms-System Integrity Program,” in the 2011 Form 10-K for details on this program; and
- A new Site Remediation Recovery Mechanism (SRRM) that allows the Company to recover prudently incurred environmental site remediation costs. This SRRM will allow recovery of one-fifth of the Company's current and future deferred expenses each year in rates, subject to an annual prudency review. A separate earnings review will be established, which will be further defined in a future proceeding.

The following items were deferred or denied by the Commission:

- The request to include prepaid pension assets in rate base and allow a return on and recovery of the asset was denied; however, the OPUC indicated in the preliminary order that it will open a docket to review the treatment of pension expense on a general, non-utility-specific basis. Until a conclusion is reached, the OPUC has authorized us to continue to collect and defer pension costs as we have historically, as outlined below;
- A recent pipeline project totaling $19.1 million was excluded from rate base, but we expect the Company will be permitted to demonstrate prudence of the project in a subsequent regulatory proceeding, with the potential effect of regulatory lag in cost recovery; and
- The recovery of deferred income taxes caused by the 2009 Oregon tax rate change was denied. As a result, we have taken a one-time after-tax charge of $2.7 million in the third quarter.

The OPUC also deferred decisions on certain issues that were raised in this proceeding including its determination to open dockets to consider: the arrangement we use to share revenues from our interstate storage operations and optimization with customers; the use of a new process to determine the appropriate amounts of working gas inventory that we earn a return on, and its corresponding rate of return; and whether prepaid pension assets should be added to rate base. A decision on these items is expected in 2013, with the working gas inventory decision expected to be applied retroactively to November 1, 2012.

The OPUC's final order may act to modify or supplement the information described herein. NW Natural will need to review and analyze the final order of the OPUC in order to more fully determine the effects of the order on NW Natural.

Rate Mechanisms

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

In October 2012, the OPUC approved PGA rate changes effective November 1, 2012. The effect of these rate changes was to decrease the average monthly bills of Oregon residential customers by about 7 percent. This was our fourth consecutive year of PGA rate decreases, and cumulatively our Oregon utility residential customer bills declined 26 percent since 2008.

In October 2012, NW Natural's WUTC PGA rates were allowed to go into effect on November 1, 2012. However, the WUTC also ordered a continuing review of hedge transactions of all Washington gas companies' PGA filings. We do not anticipate any changes to our PGA rates as filed; however, if the WUTC were to find any of our hedges to be imprudent, rates could be adjusted as a result of this review. The effect of the ordered PGA rates was to decrease the average monthly bills of Washington residential customers by about 8 percent. This was also our fourth consecutive year of PGA rate decreases in Washington, and cumulatively our Washington utility residential customer bills declined 34 percent 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.

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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 the 2010-2011, 2011-2012 and 2012-2013 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 based on the recently approved PGA, we will refund $0.7 million to customers based on the 2011 utility earnings test. We do not expect to be subject to a refund for the 2012 earnings test year.

Conservation Tariff. The Oregon conservation tariff was reauthorized in the Oregon general rate case. The conservation tariff employs a use-per-customer decoupling mechanism, which adjusts margin revenues to account for the difference between actual and expected customer volumes. The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the next annual PGA filing. Baseline consumption was determined by customer consumption data used in the Oregon general rate case. Since 2003, we have experienced a decline of approximately 12 percent in average use per residential customer and a decline of approximately 7 percent in average use per commercial customer. As a result of these declines, customers have paid surcharges related to a decoupling adjustment in seven of the past nine heating seasons. See “Business Segments - Utility Operations,” below.

Environmental Costs. As noted above, the OPUC has authorized a new environmental cost recovery mechanism as part of the general rate case. The WUTC has also authorized the deferral of environmental costs, if any, that are appropriately charged to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding. 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. 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 $6.3 million being deferred for the three and nine months ended September 30, 2012, respectively. As noted above, no change was made to our pension mechanisms as part of the general rate case.

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.

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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 utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff, which adjusts utility margin up or down through deferred accounting to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, which adjusts customer bills up or down to offset changes in utility margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of our utility's earnings and customer charges. 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 September 30, 2012 compared to September 30, 2011:

Utility operations resulted in a net loss of $11.9 million, or 44 cent cent per share, for the third quarter of 2012 compared to a net loss of $9.5 million, or 35 cents per share, for the third quarter of 2011. The increase in the 2012 net loss was primarily due to the one-time tax charge related to Oregon general rate case and higher operating expenses, partially offset by increases in utility margin. See "Application of Critical Accounting Policies and Estimates—Regulatory Cost Recovery" for additional information on the tax charge from the general rate case.

Gas Utility Volumes, Revenues and Utility Margin

Total utility volumes sold and delivered for the third quarter of 2012 were relatively flat compared to last year, while revenues were $4.4 million lower than last year but utility margin was $1.3 million higher compared to the same period last year. The decrease in revenues was primarily due to customer rate decreases, while the increase in utility margin was due to customer growth in residential and commercial sectors, gas cost incentive sharing from lower natural gas prices, and lower revenue sharing from annual utility earnings review compared to last year. The net increase in customer count was approximately 6,900 over the last twelve months, for an annual growth rate of 1.0 percent, which was up slightly from 0.8 percent for same period last year.

Nine months ended September 30, 2012 compared to September 30, 2011:

In the nine months ended September 30, 2012, utility operations contributed net income of $28.3 million or $1.05 per share, compared to $31.7 million or $1.19 per share in 2011. The decrease in net income was primarily due to the one-time tax charge related to general rate case, higher operating expenses and the effects of warmer weather on utility margin. These factors were partially offset by increases in utility margin. See "Application of Critical Accounting Policies and Estimates—Regulatory Cost Recovery" for additional information on the tax charge from the general rate case.

Gas Utility Volumes, Revenues and Utility Margin

Total utility volumes sold and delivered in the nine months ended September 30, 2012 decreased by 2 percent over last year primarily due to 10 percent warmer weather, while total utility margin increased by $6.7 million, or 3 percent. The increase in utility margin was primarily attributed to a one-time, pre-tax charge of $7.4 million in the first nine months of 2011 related to the repeal of utility tax legislation in Oregon, and a $3.6 million gain, or a $2.2 million increase over last year, from higher gas cost incentive sharing resulting from lower gas commodity prices. In addition, the increase was also due to a 1 percent increase in customers over last year. These increases to margin were partially offset by declines in customer volumes and the timing of colder weather in May 2011 compared to 2012 as the weather normalization mechanism for customer usage ends on May 15th while the decoupling mechanism assumes weather adjusted volumes for the entire month.

During the nine months ended September 30, 2012, our weather normalization mechanism adjusted residential and commercial margins down by $3.8 million based on temperatures that were 2 percent colder than average, compared to a margin decrease of $10.6 million last year when temperatures were 12 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins up by $6.8 million for the nine months ended September 30, 2012 and $10.8 million for the nine months ended September 30, 2011, to largely offset the impact of lower average use per customer on a weather normalized basis.

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The following tables summarize the composition of gas utility volumes, revenues and margin. Certain amounts in prior year balances under the utility margin section of the tables have been reclassified to conform with the current year's presentation. These reclassifications reflect amounts moved from other utility 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 these reclassifications.

	Three Months Ended Three Months Ended Three Months Ended September 30,		Favorable/ (Unfavorable)
Thousands, except degree day and customer data	2012	2011	2012 vs. 2011
Utility volumes - therms:			
Residential sales	28,369	28,809	(440)
Commercial sales	25,117	25,001	116
Industrial - firm sales	7,506	7,843	(337)
Industrial - firm transportation	26,952	28,570	(1,618)
Industrial - interruptible sales	12,081	11,815	266
Industrial - interruptible transportation	58,339	55,828	2,511
Total utility volumes sold and delivered	158,364	157,866	498
Utility operating revenues - dollars:			
Residential sales	$38,937	$41,233	$(2,296)
Commercial sales	25,183	26,454	(1,271)
Industrial - firm sales	5,930	6,539	(609)
Industrial - firm transportation	1,724	1,527	197
Industrial - interruptible sales	6,258	7,019	(761)
Industrial - interruptible transportation	2,076	2,368	(292)
Regulatory adjustment for income taxes paid(1)	—	3	(3)
Other revenues	2,048	1,405	643
Total utility operating revenues	82,156	86,548	(4,392)
Cost of gas sold	37,570	43,117	(5,547)
Revenue taxes	2,255	2,397	(142)
Utility margin	$42,331	$41,034	$1,297
Utility margin:(2)			
Residential sales	$22,681	$22,836	$(155)
Commercial sales	10,165	10,136	29
Industrial - sales and transportation	6,727	6,623	104
Miscellaneous revenues	668	867	(199)
Gain from gas cost incentive sharing	467	186	281
Other margin adjustments	1,315	487	828
Margin before regulatory adjustments	42,023	41,135	888
Weather normalization adjustment	—	—	—
Decoupling adjustment	308	(104)	412
Regulatory adjustment for income taxes paid(1)	—	3	(3)
Utility margin	$42,331	$41,034	$1,297
Customers - end of period:			
Residential customers	615,642	609,159	6,483
Commercial customers	62,648	62,204	444
Industrial customers	919	915	4
Total number of customers - end of period	679,209	672,278	6,931

Actual degree days	58	50
Percent colder (warmer) than average weather[3]	43 %	(51)%

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Thousands, except degree day and customer data	Nine Months Ended September 30, 2012	2011	Favorable/ (Unfavorable) 2012 vs. 2011
Utility volumes - therms:			
Residential sales	268,503	281,862	(13,359)
Commercial sales	168,913	175,410	(6,497)
Industrial - firm sales	25,718	27,183	(1,465)
Industrial - firm transportation	95,539	97,585	(2,046)
Industrial - interruptible sales	44,001	43,347	654
Industrial - interruptible transportation	182,866	176,645	6,221
Total utility volumes sold and delivered	785,540	802,032	(16,492)
Utility operating revenues - dollars:			
Residential sales	$288,714	$331,835	$(43,121)
Commercial sales	146,126	169,566	(23,440)
Industrial - firm sales	18,716	22,264	(3,548)
Industrial - firm transportation	5,411	4,901	510
Industrial - interruptible sales	21,261	25,753	(4,492)
Industrial - interruptible transportation	6,143	6,968	(825)
Regulatory adjustment for income taxes paid(1)	—	(7,162)	7,162
Other revenues	5,061	4,095	966
Total utility operating revenues	491,432	558,220	(66,788)
Cost of gas sold	241,823	313,781	(71,958)
Revenue taxes	12,688	14,195	(1,507)
Utility margin	$236,921	$230,244	$6,677
Utility margin:(2)			
Residential sales	$145,923	$150,855	$(4,932)
Commercial sales	58,444	59,923	(1,479)
Industrial - sales and transportation	21,114	21,073	41
Miscellaneous revenues	3,634	3,977	(343)
Gain from gas cost incentive sharing	3,556	1,308	2,248
Other margin adjustments	1,333	92	1,241
Margin before regulatory adjustments	234,004	237,228	(3,224)
Weather normalization adjustment	(3,834)	(10,612)	6,778
Decoupling adjustment	6,751	10,790	(4,039)
Regulatory adjustment for income taxes paid(1)	—	(7,162)	7,162
Utility margin	$236,921	$230,244	$6,677
Actual degree days	2,717	2,968	
Percent colder than average weather(3)	2%	12%	

(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 2003 Oregon general rate case.

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Residential and Commercial Sales

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

The primary factors contributing to changes in residential and commercial markets in the third quarter of this year as compared to the same period last year were:

- sales volumes remained relatively flat compared to the prior year;
- utility operating revenues decreased $3.6 million or 5 percent, primarily due to $1.9 million of credits to customers' bills in July related to the refund of gas cost savings and lower billing rates to customers from a PGA rate decrease effective November 1, 2011; and
- utility margin remained relatively flat compared to the prior year.

Nine months ended September 30, 2012 compared to September 30, 2011:

The primary factors contributing to changes in residential and commercial markets for the nine months ended September 30, 2012 compared to September 30, 2011 were as follows:

- utility sales volumes were 4 percent lower, primarily reflecting 10 percent warmer weather;
- utility operating revenues decreased $66.6 million or 13 percent primarily due to $36.2 million of credits to customers' bills primarily in June related to the refund of gas cost savings, as well as the effects of warmer weather and lower billing rates to customers; and
- utility margin decreased $3.7 million or 2 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 in Oregon increases or decreases. The decrease in margin reflects the warmer weather compared to last year's very cold weather, and the timing of the colder weather in the prior year when the full impact of the weather normalization mechanisms was in effect.

Industrial Sales and Transportation

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

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

- volumes delivered to industrial customers remained relatively flat with an increase of only 0.8 million therms, or less than 1 percent; and
- margin from industrial customers contributed a slight increase of $0.1 million, or 2 percent, to operating income.

Nine months ended September 30, 2012 compared to September 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 3.4 million therms, or 1 percent, primarily reflecting the impact of customers switching to natural gas due to the lower prices of natural gas compared to oil; and
- utility margin from industrial customers remained flat.

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. This law was repealed in 2011. As a result, we did not recognize any income or expense related to this regulatory adjustment for the three and nine months ended September 30, 2012, while 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.

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Other Revenues

Other revenues include miscellaneous fee income and other regulatory adjustments. Other revenues were $2.0 million in the third quarter of 2012, an increase of $0.6 million over the third quarter of 2011. Other revenues were $5.1 million in the nine months ended September 30, 2012, an increase of $1.0 million over the same period of 2011.

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 actual cost incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism whereby we either increase or decrease margin results based on a percentage of actual gas costs as compared to embedded gas costs in the PGA. Under this provision, our net income can be affected by differences between actual and expected gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases in the PGA (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, which is reflected in utility margin (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 September 30, 2012 compared to September 30, 2011:

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

- total cost of gas sold decreased $5.5 million, or 13 percent, including the $1.9 million of credits applied to customer billings in July 2012 related to the refund of gas cost savings. Excluding the customer credits, total cost of gas decreased $3.6 million or 8 percent, primarily reflecting lower natural gas prices;
- average gas cost collected through rates, excluding customer refunds for gas cost savings, decreased from 61 cents per therm in 2011 to 54 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 $12.7 million were realized and included in cost of gas sold this quarter, compared to $6.6 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 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 third quarter of 2012, compared to a margin gain of $0.2 million for the third quarter of 2011.

Nine months ended September 30, 2012 compared to September 30, 2011:

- total cost of gas sold decreased $72.0 million, or 23 percent, including the $37.7 million of credits applied to customer billings primarily in June 2012 related to the refund of gas cost savings. Excluding the customer credits, total cost of gas decreased $34.3 million or 11 percent, primarily reflecting lower usage due to weather that was 10 percent warmer than the same period in 2011;

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- 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 $63.3 million were realized and included in cost of gas sold for the nine months ended September 30, 2012, compared to $36.2 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 $3.6 million in the first nine months of 2012 compared to $1.3 million in 2011. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our 75 percent ownership interest in the Gill Ranch underground storage facility in California.

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

For the three months ended September 30, 2012, we earned $1.3 million, or 5 cents per share, compared to $1.2 million, or 4 cents per share, for the same period in 2011. Gas storage operating income increased $1.2 million to $3.6 million for the three months ended September 30, 2012. The increase in net income over 2011 primarily reflects higher revenues from an increase in contracted capacity and lower than expected operating costs, partially offset by higher interest expense from Gill Ranch's $40 million senior secured debt, which was issued in the fourth quarter of 2011, and lower market prices for storage.

Nine months ended September 30, 2012 compared to September 30, 2011:

Our gas storage segment earnings remained flat with $3.2 million of net income, or 12 cents per share for both the nine months ended September 30, 2012 and 2011. Gas storage operating income increased $2.4 million to $9.6 million for the nine months ended September 30, 2012. This increase in operating income was primarily due to increased revenues from Gill Ranch from higher contracted capacity.

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 and $0.9 million as of September 30, 2012 and 2011, respectively, 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 September 30, 2012 and 2011 was $13.4 million and $14.4 million, respectively, with the year-over-year decrease reflecting a $1.0 million write-down taken in the fourth quarter of 2011. In aggregate, earnings from our other business segment for the nine months ended September 30, 2012 and 2011 were a slight gain and a net loss of $0.2 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.

Consolidated Operations

Operations and Maintenance

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

Operations and maintenance expense was $29.0 million in 2012 compared to $28.4 million in 2011, for an increase of $0.6 million or 2 percent. The primary factors contributing to the increase were:

- a $0.8 million increase in utility non-payroll expense including higher costs for safety enhancements, business development, information technology system maintenance and other customer service cost increases;
- a $0.2 million increase in utility payroll expense primarily related to an increase in field service employees; and
- a $0.2 million increase in utility employee benefit expense, primarily related to health care and pension costs. See below for additional discussion on pension costs.

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Partially offsetting the above factors was:

- a $1.0 million decrease in utility performance awards; and
- a $0.2 million reduction in gas storage general and administrative expense reflecting lower costs as compared to start-up costs incurred at Gill Ranch in 2011.

Nine months ended September 30, 2012 compared to September 30, 2011:

Operations and maintenance expense was $95.5 million in 2012 compared to $89.9 million in 2011, for an increase of $5.6 million or 6 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense for the nine months ended September 30, 2012 compared to September 30, 2011:

- a $2.7 million increase in utility payroll expense primarily related to an increase in field service employees;
- a $2.6 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; and
- a $1.1 million increase in utility employee benefit expense, principally related to health care and pension costs. See below for additional discussion on pension costs.

Partially offsetting the above factors were:

- a $0.6 million reduction in gas storage general and administrative expense primarily reflecting lower costs as compared to start-up costs incurred at Gill Ranch in the first nine months of 2011; and
- a $0.1 million decrease in utility bad debt expense.

Our bad debt expense decreased in the third quarter of 2012 partially due to the positive impact of customer refunds on delinquent balances during the period. Our bad debt expense as a percent of revenues was 0.23 percent for the twelve months ended September 30, 2012, compared to 0.24 percent for the same period last year. This year's increase in bad debt as a percent of revenues is largely due to the revenue decrease of approximately $39 million representing the refund of accumulated gas cost savings for customers. Our bad debt expense results continue at historically low levels for the Company despite challenging economic conditions in recent years. We believe credit risks are still somewhat 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 in 2012 largely due to lower interest rates; however, the OPUC approved a deferral of our utility pension costs for amounts in excess of what is currently recovered in customer rates. The pension cost deferral is recorded to a regulatory balancing account, which reduces operations and maintenance expense. For the three and nine months ended September 30, 2012, we deferred pension expenses totaling $2.1 million and $6.3 million, respectively, and $1.3 million and $4.0 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 operations, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—Pension Deferral," above.

General Taxes

General taxes remained flat at $7.5 million for both the three months ended September 30, 2012 and September 30, 2011. However, general taxes increased $1.4 million in the first nine months of 2012 compared to 2011, primarily due to a $0.8 million increase in property taxes at Gill Ranch to reflect increased capital investments added to our assessed tax base for 2012.

Depreciation and Amortization

Depreciation and amortization expense increased by $0.8 million, or 5 percent for the three months ended September 30, 2012, compared to the same period in 2011. For the nine months ended September 30, 2012, depreciation and amortization expense increased by $2.0 million, or 4 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Thousands	2012	2011	2012	2011
Gains from company-owned life insurance	$510	$286	$1,902	$1,485
Interest income	9	6	114	36
Income from equity investments	21	(1)	22	(354)
Net interest on deferred regulatory accounts	1,499	1,548	3,339	4,563
Gain (loss) on sale of investments	—	—	—	(96)
Other non-operating	(329)	(58)	(1,741)	(1,517)
Total other income and expense - net	$1,710	$1,781	$3,636	$4,117

Other income and expense – net for the nine months ended September 30, 2012 decreased $0.5 million primarily due to $1.2 million of lower interest from net regulatory account balances. Net regulatory account balances in the first half of 2012 were lower due to environmental insurance recoveries received at the end of 2011 as well as accumulated gas cost savings from November 2011 through June 2012. The company's refund of gas cost savings has increased the regulatory account balances which has resulted in higher interest in the third quarter of 2012. This decrease in other income and expense is partially offset by increases of $0.4 million and $0.4 million in income from equity investments and gains from life insurance policy proceeds, respectively.

Interest Expense – Net

Interest expense – net increased $0.3 million and $1.2 million for the three and nine months ended September 30, 2012, respectively, compared to the same periods in 2011. The increase was primarily due to interest on our new $40 million senior secured debt at Gill Ranch, which was issued in the fourth quarter of 2011, partially offset by a redemption earlier this year of a $40 million utility long-term debt issue with a coupon rate of 7.13 percent.

Income Tax Benefit/Expense

Income tax benefit decreased $2.7 million for the three months ended September 30, 2012 while income tax expense increased $2.3 million for the nine months ended September 30, 2012, compared to the same periods in 2011. This was primarily due to a $2.7 million one-time, after-tax charge related to the Oregon general rate case. See Note 9, Application of Critical Accounting Policies and Estimates—Regulatory Cost Recovery, and Results of Operations—Regulatory Matters—Oregon General Rate Case for additional information on the tax charge from the general rate case.

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Financial Condition

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt redemptions and short-term commercial paper maturities (see “Liquidity and Capital Resources,” below, and Note 7). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at September 30, 2012 and 2011 and at December 31, 2011 was as follows:

	September 30,				December 31,	
	2012		2011		2011	
Common stock equity	46.7	%	45.8	%	46.5	%
Long-term debt	41.8	%	39.6	%	41.7	%
Short-term debt, including current maturities of long-term debt	11.5	%	14.6	%	11.8	%
Total	100	%	100	%	100	%

Liquidity and Capital Resources

At September 30, 2012, we had $5.7 million of cash and cash equivalents compared to $25.9 million at September 30, 2011. We also had $4.0 million in restricted cash at Gill Ranch as of September 30, 2012 which is being held as collateral for the long-term debt outstanding. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances, add short-term borrowing capacity, or pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC, and our use of proceeds from utility specific issuances are restricted to certain utility purposes. Our use of retained earnings is not subject to those same restrictions.

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

Capital markets over the past few years, including the commercial paper market, experienced significant volatility and tight credit conditions, but current market conditions are significantly better as reflected by tighter credit spreads and increased access to financing for investment grade issuers. Based on our current debt ratings (see “Credit Ratings,” below), we have been able to issue commercial paper and first mortgage bonds at attractive rates and have not needed to borrow from our back-up credit facilities. In the event that we are not able to issue new debt due to market conditions, we expect that our near term liquidity needs can be met by using cash balances or, for the utility segment, drawing upon our committed credit facilities. We also have a universal shelf registration filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of September 30, 2012, we had OPUC approval to issue up to $125 million of additional debt for approved purposes, of which $75 million was remaining for issuance after NW Natural issued $50 million of first mortgage bonds on October 30, 2012.

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional cash requirements and may trigger significant increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on September 30, 2012, we could have been required to post $1 million of collateral to our counterparties, if our long-term debt ratings were at non-investment grade levels, which would be a very significant change from current rating levels for NW Natural (see Note 12 and “Credit Ratings,” below).

In July 2010, the U.S. Congress passed and President Obama signed into law the “Dodd-Frank Wall Street Reform and Consumer Protection Act” (Dodd-Frank Act). The legislation established a new statutory framework for the comprehensive regulation of financial institutions that participate in the swaps market and, among other things, requires additional government regulation of derivative and over-the-counter transactions and expanded collateral requirements. In July 2012, pursuant to the Dodd-Frank Act, the Commodity Futures Trading Commission (CFTC) and SEC issued rules that further define the term “Swap,” and provide enhanced record keeping and reporting requirements. The CFTC rules regarding clearing swaps are not yet final. However, if clearing is required for qualifying end-users, such as NW Natural, the Company will be required to post collateral with a clearing firm. The minimum liquidity required, in the form of either posting cash or having an increased line of credit availability, will be, if required, higher than the Company's current collateral exposure levels. At this time, we do not expect the rules to have a material impact on our financial statements and disclosures. The Company currently does not qualify as a swap dealer nor believe it will in the future based on current or anticipated rules. We will continue to monitor interpretations and CFTC guidance to determine the impact, if any, on our hedging policies, procedures, results of operations, financial position and liquidity.

Other recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, tax benefits and liabilities, environmental expenditures and insurance recoveries, and customer refunds of gas cost savings. With respect to pension requirements, we expect to make significant contributions over the next several years until we are fully funded under the Pension Protection Act rules, including the new rules issued under the MAP-21 Act (see "Application of Critical Accounting Policies - Pension Contributions," above, and “Pension Cost and Funding Status of Qualified Retirement Plans,” below). With respect to federal income tax liabilities, an extension was granted that allowed us to take 100 percent bonus depreciation on qualified expenditures during 2011, and allows 50 percent bonus depreciation on a majority of our capital expenditures in 2012, which significantly reduces our tax liability for those tax years and provides cash flow benefits in 2012 and 2013. With respect to environmental liabilities, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance and utility rates over the next several years, even though the amount and timing of these expenditures and recoveries is uncertain (see Note 13, "Results of Operations—Regulatory Matters—Oregon General Rate Case" above and “Cash Flows—Operating Activities” below).

With respect to customer refunds or credits, gas prices were significantly lower between November 1, 2011 and March 31, 2012 than the gas prices embedded in customer rates. As a result, our PGA incentive sharing mechanism deferred 90 percent of these gas cost savings attributed to Oregon, and 100 percent of the savings attributed to Washington, into a regulatory account for refund back to customers (see “Purchased Gas Adjustment,” above). Ordinarily, these refunds would be credited to customer rates in the next year’s PGA filing, but in the second quarter of 2012 the company received regulatory approval to immediately credit $35 million to Oregon customers and $4 million to Washington customers through billing credits. In addition, the company also received approval to provide its Oregon utility customers with a $9 million interstate storage credit from our regulatory incentive sharing mechanism related to gas storage and asset management services. These credits were applied to customer bills in June and July of 2012.

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

Under the note agreements, Gill Ranch is subject to certain covenants and restrictions, including but not limited to a financial covenant that requires Gill Ranch to maintain minimum adjusted EBITDA at various levels over the term of the notes. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the agreements, Gill Ranch is also subject to a debt service reserve requirement of 10 percent of the outstanding principal amount, initially $4 million, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on the incurrence of additional debt. At September 30, 2012, we were in compliance with all covenants and restrictions for the note agreements.

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

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Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas inventories and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities (see "Credit Agreements," below). Our commercial paper program did not experience any liquidity disruptions as a result of the credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs over the last several years. At September 30, 2012 and 2011, our utility had commercial paper outstanding of $175.8 million and $181.2 million, respectively. The effective interest rate on the utility's commercial paper outstanding at September 30, 2012 and 2011 was 0.3 percent.

Credit Agreements

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling $250 million. The original term of this credit agreement was extended through May 31, 2013. All lenders under our syndicated agreement are major financial institutions with committed balances and investment grade credit ratings as of September 30, 2012 (see table below).

Lender rating, by category	Loan Commitment Amounts in Thousands Syndicated Facility
AA/Aa	$165,000
A/A1	85,000
BBB/Baa	—
Total	$250,000

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

As discussed above, we have commitments with all of our lenders under the $250 million syndicated agreement through May 31, 2013. This syndicated agreement allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million. This syndicated agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. This credit facility is scheduled to expire next year, but we intend to enter into a new agreement to replace the existing facility.

Any principal and unpaid interest amounts owed on borrowings under the credit agreements are due and payable on or before the maturity date. There were no outstanding balances under these credit agreements at September 30, 2012 and 2011. These agreements require us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at September 30, 2012 and 2011, with consolidated indebtedness to total capitalization ratios of 53 percent and 54 percent, respectively.

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

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Credit Ratings

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

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

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

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

Maturity and Redemption of Long-Term Debt

For the nine months ended September 30, 2012, $40 million of first mortgage bonds with a coupon rate of 7.13% were redeemed at maturity. Over the next twelve months, there are no scheduled maturities or redemptions of long-term debt. For long-term debt maturing over the next five years, see "Contractual Obligations" in our 2011 Form 10-K.

Cash Flows

Operating Activities

Nine months ended September 30, 2012 compared to September 30, 2011:

For the nine months ended September 30, 2012, cash flow from operating activities totaled $178.1 million, compared to $191.3 million in 2011. Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements, and other cash and non-cash adjustments to operating results. The significant factors contributing to changes in operating cash flow in the first nine months of 2012 compared to 2011 are as follows:

- an increase of $13.8 million from reductions in receivable balances primarily due to higher receivable balances from colder weather at the end of 2011, which were collected early in 2012;
- an increase of $10.4 million in other-net primarily related to an increase in net collections of deferred regulatory asset balances;
- an increase of $8.5 million in accounts payable balances, primarily due to an increase in customer equal payment plan balances, and the timing of payroll tax payments in 2012 compared to 2011;
- a decrease of $31.8 million in taxes accrued, primarily related to federal tax refunds totaling $36.6 million received in 2011; and
- a decrease of $15.8 million from changes in the deferred gas cost savings balance, which was reduced when mid-year balances were refunded to customers in June 2012.

Also affecting cash flow from operating activities is the amount of cash contributions made to the utility's qualified defined benefit pension plans. During the nine months ended September 30, 2012, we contributed $23.5 million to these plans, which was significantly higher than the $4.3 million in non-cash expense recognized on the income statement, compared to contributions of $19.2 million and $5.5 million in non-cash expense for the same nine month period in 2011. We expect pension contributions to exceed non-cash expense for the next few years, but contribution amounts will be less than previously anticipated due to funding relief approved under the new MAP-21 Act in July 2012. We are currently evaluating the impact of these new funding rules and the amounts and timing of these expenses will depend on market interest rates and investment returns on the plans' assets.

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Also significantly affecting cash flows over the past few years has been income tax relief, including the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the Tax Relief Act). the Tax Relief Act allowed 100 percent bonus depreciation on qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50 percent bonus depreciation deduction to qualifying property placed in service during 2012. These and other tax benefits resulted in a net operating tax loss for 2010, which was carried back to the tax year 2009 and resulted in a federal income tax refund of $22.3 million received in 2011. We generated taxable income in 2011 that was fully offset by net operating loss (NOL) carried forward from 2010. We continue to generate NOL carry-forwards during 2012. As of September 30, 2012, we had an estimated federal income tax receivable balance of $1.8 million and an estimated NOL carry-forward balance of $41.3 million to 2013. We anticipate being able to use the full amount of the current NOL carry-forward balance in future years. The federal NOL from 2010 would expire in 2031, if not used in earlier years.

Investing Activities

Nine months ended September 30, 2012 compared to September 30, 2011:

Cash used in investing activities for the nine months ended September 30, 2012 totaled $142.5 million, up from $100.2 million for the same period in 2011. Capital expenditures were $100.9 million in the nine months ended September 30, 2012, up from $70.0 million for the same period in 2011, which was largely driven by utility facilities projects as noted below. We also invested $41.8 million in utility gas reserves in the first nine months of 2012 compared to $30.9 million in the same period of 2011.

In 2012, we purchased a property in Sherwood, Oregon, which will enable us to consolidate and streamline certain field operations and maintenance groups, and provide us with advanced pipeline training facilities as well as a back-up emergency operations site.

For the year 2012, we expect to spend up to $150 million on utility capital projects and up to $5 million on non-utility capital projects. Gas storage capital expenditures in 2012 are expected to be paid primarily from working capital. For more information on capital projects, see "Cash Flows—Investing Activities" in the 2011 Form 10-K, and for more information on utility and non-utility investment opportunities, see Note 11 and "Strategic Opportunities," above.

Financing Activities

Nine months ended September 30, 2012 compared to September 30, 2011:

Cash used in financing activities during the nine months ended September 30, 2012 totaled $35.6 million, down from cash used of $68.7 million for the same period in 2011. The main driver of this decrease in financing activity is our short-term debt balances which increased $34.2 million in the nine months ended September 30, 2012, compared to a decrease of $76.2 million for the same period in 2011. This decrease was offset by a $30 million increase in long-term debt redemptions in 2012 along with a $50 million decrease in long-term debt issued. We continue to use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt maturities, and for other general corporate purposes.

Pension Cost and Funding Status of Qualified Retirement Plans

We make pension contributions to company-sponsored qualified defined benefit plans based on actuarial assumptions and estimates, tax regulations and funding laws. Our qualified defined benefit plans were underfunded by $146.9 million at December 31, 2011. For the nine months ended September 30, 2012, we made cash contributions totaling $23.5 million into our Company sponsored qualified pension plans in accordance with the Pension Protection Act of

2006. In July 2012, Congress passed legislation called the MAP-21, which among other things includes a method of stabilizing interest rate assumptions and minimum funding requirements for our qualified plans. Under MAP-21, we expect to continue making contributions to these qualified plans but most likely at reduced levels over the next three years. For more information on the funded status of our qualified retirement plans and other postretirement benefits, see Note 8, and Part II, Item 7., “Financial Condition—Pension Cost and Funding Status of Qualified Retirement Plans,” and Part II, Item 8., Note 9, “Pension and Other Postretirement Benefits,” in the 2011 Form 10-K.

We also contribute to a multi-employer union pension plan (Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.3 million to the Western States Plan in both the nine months ended September 30, 2012 and 2011, and we expect to contribute a total of $0.4 million during 2012. See Note 8 for further discussion. We continue to evaluate our ongoing participation in this and overall retirement benefit plans with bargaining unit employees.

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Ratios of Earnings to Fixed Charges

For the nine and twelve months ended September 30, 2012 and the twelve months ended December 31, 2011, our ratios of earnings to fixed charges, were 2.70, 3.29 and 3.41 respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. See Exhibit 12.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies (see Part II, Item 7., “Application of Critical Accounting Policies and Estimates,” in our 2011 Form 10-K). At September 30, 2012, we had a regulatory asset of $128.2 million for deferred environmental costs, which includes $78.4 million for additional costs expected to be paid in the future and $22.3 million of accrued interest. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 13 and "Results of Operations—Regulatory Matters—Oregon General Rate Case" above.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price and storage value risk, interest rate risk, foreign currency risk, credit risk and weather risk. We monitor and manage these financial exposures as an integral part of our overall risk management program. No material changes have occurred related to our disclosures about market risk for the nine month period ending September 30, 2012. See Part I, Item 1A., “Risk Factors,” and Part II, Item 7A. “Quantitative and Qualitative Disclosures about Market Risk,” in the 2011 Form 10-K and Part II, Item 1A., “Risk Factors,” in this report for details regarding these risks.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

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

(b) Changes in Internal Control Over Financial Reporting

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

There have been no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

PART II. OTHER INFORMATION
ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

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

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

The following table provides information about purchases by us during the quarter ended September 30, 2012 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASE OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (2)
Balance forward			2,124,528	$ 16,732,648
07/01/12 - 07/31/12	—	$—	—	—
08/01/12 - 08/31/12	2,689	49.19	—	—
09/01/12 - 09/30/12	—	—	—	—
Total	2,689	$49.19	2,124,528	$ 16,732,648

(1) During the quarter ended September 30, 2012, 2,689 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended September 30, 2012, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2013 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended September 30, 2012, no shares of our common stock were purchased pursuant to this program. Since the program's inception in 2000 we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

ITEM 6. EXHIBITS

See Exhibit Index attached hereto.

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SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)
Dated: November 6, 2012

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

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NORTHWEST NATURAL GAS COMPANY
EXHIBIT INDEX
To
Quarterly Report on Form 10-Q
For the Quarter Ended
September 30, 2012

Exhibit Number	Document
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.