NORTHWEST NATURAL GAS CO
Form 10-Q
November 03, 2015

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, 2015

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to____________
Commission file number 1-15973

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

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

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

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

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

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

Large Accelerated Filer [X]	Accelerated Filer [ ]
Non-accelerated Filer [ ] (Do not check if a Smaller Reporting Company)	Smaller Reporting Company [ ]

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

At October 23, 2015, 27,371,642 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, 2015

TABLE OF CONTENTS

Table of Contents

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”, "predicts", "projects" and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans, objectives, goals, and strategies;
- assumptions and estimates;
- future events or performance;
- trends, timing and cyclicality;
- risks;
- earnings and dividends;
- capital structure;
- growth;
- customer rates;
- commodity costs;
- gas reserves;
- operational performance and costs;
- energy policy and preferences;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- project and program development, expansion, or investment;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate or regulatory recovery or refunds;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- levels and pricing of gas storage contracts;
- local or national disasters, pandemic illness, terrorist activities, including cyber-attacks, and other extreme events;
- outcomes and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- approval and adequacy of regulatory deferrals;
- potential regulatory disallowances;
- effects of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs and recoveries, and the timing thereof.

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 2014 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.

Table of Contents

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

In thousands, except per share data	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating revenues	$93,128	$87,199	$493,073	$513,754
Operating expenses:				
Cost of gas	35,856	32,227	223,737	245,708
Operations and maintenance	32,031	32,968	121,458	103,085
General taxes	6,772	7,143	23,153	22,508
Depreciation and amortization	20,342	19,938	60,683	59,236
Total operating expenses	95,001	92,276	429,031	430,537
Income (loss) from operations	(1,873)	(5,077)	64,042	83,217
Other income and expense, net	746	407	6,930	2,052
Interest expense, net	10,111	10,805	31,030	34,024
Income (loss) before income taxes	(11,238)	(15,475)	39,942	51,245
Income tax expense (benefit)	(4,553)	(6,742)	15,944	21,023
Net income (loss)	(6,685)	(8,733)	23,998	30,222
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $217 and $108 for the three months ended and $650 and $324 for the nine months ended September 30, 2015 and 2014, respectively	332	166	995	497
Comprehensive income (loss)	$(6,353)	$(8,567)	$24,993	$30,719
Average common shares outstanding:				
Basic	27,363	27,189	27,336	27,145
Diluted	27,363	27,189	27,399	27,195
Earnings (loss) per share of common stock:				
Basic	$(0.24)	$(0.32)	$0.88	$1.11
Diluted	(0.24)	(0.32)	0.88	1.11
Dividends declared per share of common stock	0.465	0.460	1.395	1.380

See Notes to Unaudited Consolidated Financial Statements

2

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	September 30, 2015	September 30, 2014	December 31, 2014
Assets:			
Current assets:			
Cash and cash equivalents	$5,227	$8,275	$9,534
Accounts receivable	29,800	30,468	69,818
Accrued unbilled revenue	15,752	12,442	57,963
Allowance for uncollectible accounts	(308)	(840)	(969)
Regulatory assets	82,712	52,250	68,562
Derivative instruments	2,956	5,587	243
Inventories	80,974	86,600	77,832
Gas reserves	17,822	21,455	20,020
Income taxes receivable	—	7,639	1,000
Deferred tax assets	15,663	5,100	23,785
Other current assets	27,313	19,158	34,772
Total current assets	277,911	248,134	362,560
Non-current assets:			
Property, plant, and equipment	3,072,998	2,990,662	2,992,560
Less: Accumulated depreciation	905,137	883,568	870,967
Total property, plant, and equipment, net	2,167,861	2,107,094	2,121,593
Gas reserves	117,784	131,745	129,280
Regulatory assets	333,953	263,321	368,908
Derivative instruments	299	602	—
Other investments	68,503	67,980	68,238
Restricted cash	4,500	3,000	3,000
Other non-current assets	7,554	11,648	11,366
Total non-current assets	2,700,454	2,585,390	2,702,385
Total assets	$2,978,365	$2,833,524	$3,064,945

See Notes to Unaudited Consolidated Financial Statements

3

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	September 30, 2015	September 30, 2014	December 31, 2014
Liabilities and equity:			
Current liabilities:			
Short-term debt	$225,200	$190,000	$234,700
Current maturities of long-term debt	—	40,000	40,000
Accounts payable	54,425	71,018	91,366
Taxes accrued	11,854	11,876	10,031
Interest accrued	9,800	10,427	6,079
Regulatory liabilities	34,127	23,352	19,105
Derivative instruments	21,949	5,520	29,894
Other current liabilities	27,924	33,481	38,235
Total current liabilities	385,279	385,674	469,410
Long-term debt	621,700	621,700	621,700
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	527,336	499,809	530,965
Regulatory liabilities	334,490	312,500	317,205
Pension and other postretirement benefit liabilities	228,861	142,502	236,735
Derivative instruments	3,540	551	3,515
Other non-current liabilities	117,950	118,531	118,094
Total deferred credits and other non-current liabilities	1,212,177	1,073,893	1,206,514
Commitments and contingencies (see Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,367, 27,203, and 27,284 at September 30, 2015 and 2014 and December 31, 2014, respectively	380,208	371,657	375,117
Retained earnings	388,082	386,461	402,280
Accumulated other comprehensive loss	(9,081)	(5,861)	(10,076)
Total equity	759,209	752,257	767,321
Total liabilities and equity	$2,978,365	$2,833,524	$3,064,945

See Notes to Unaudited Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

In thousands	Nine Months Ended September 30, 2015	2014
Operating activities:		
Net income	$23,998	$30,222
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	60,683	59,236
Regulatory amortization of gas reserves	13,606	13,795
Deferred tax liabilities, net	7,153	10,721
Non-cash expenses related to qualified defined benefit pension plans	4,238	3,795
Contributions to qualified defined benefit pension plans	(11,780)	(10,500)
Deferred environmental (expenditures), net of recoveries	(8,063)	89,537
Non-cash regulatory disallowance of prior environmental cost deferrals	15,000	—
Non-cash interest income on deferred environmental expenses	(5,322)	—
Other	669	(1,692)
Changes in assets and liabilities:		
Receivables	82,586	100,931
Inventories	(3,142)	(25,931)
Taxes accrued	2,823	(3,085)
Accounts payable	(36,230)	(28,762)
Interest accrued	3,721	3,324
Deferred gas costs	27,042	(22,173)
Other, net	(4,237)	(4,554)
Cash provided by operating activities	172,745	214,864
Investing activities:		
Capital expenditures	(86,923)	(86,552)
Utility gas reserves	(1,165)	(21,734)
Restricted cash	(1,500)	1,000
Other	1,346	82
Cash used in investing activities	(88,242)	(107,204)
Financing activities:		
Common stock issued, net	1,252	5,460
Long-term debt retired	(40,000)	(80,000)
Change in short-term debt	(9,500)	1,800
Cash dividend payments on common stock	(38,122)	(37,442)
Other	(2,440)	1,326
Cash used in financing activities	(88,810)	(108,856)
Decrease in cash and cash equivalents	(4,307)	(1,196)
Cash and cash equivalents, beginning of period	9,534	9,471
Cash and cash equivalents, end of period	$5,227	$8,275
Supplemental disclosure of cash flow information:		
Interest paid	$25,264	$30,701
Income taxes paid (net of refunds)	10,631	14,945

See Notes to Unaudited Consolidated Financial Statements

5

NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies we directly or indirectly control, either through majority ownership or otherwise. We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other.

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and NW Natural Gas Reserves, LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method, which includes NWN Energy’s investment in Trail West Holdings, LLC (TWH) and NNG Financial's investment in Kelso-Beaver (KB) Pipeline. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated unaudited financial statements are presented after elimination of all 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 businesses and other non-utility investments and business activities.

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments management considers necessary for fair presentation 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 2014 Annual Report on Form 10-K (2014 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 full year results.

2. SIGNIFICANT ACCOUNTING POLICIES

Significant accounting policies are described in Note 2 of the 2014 Form 10-K. There were no material changes to those accounting policies during the nine months ended September 30, 2015. The following are current updates to certain critical accounting policy estimates and new accounting standards.

Table of Contents

Regulatory Accounting

In applying regulatory accounting in accordance with generally accepted accounting principles in the United States of America (GAAP), we capitalize or defer certain costs and revenues as regulatory assets and liabilities. These deferrals were as follows:

	Regulatory Assets		
	September 30,		December 31,
In thousands	2015	2014	2014
Current:			
Unrealized loss on derivatives(1)	$21,949	$5,520	$29,889
Gas costs	19,274	23,795	21,794
Environmental costs(2)	12,364	—	—
Decoupling(3)	19,391	11,847	2,219
Other(3)	9,734	11,088	14,660
Total current	$82,712	$52,250	$68,562
Non-current:			
Unrealized loss on derivatives(1)	$3,540	$551	$3,515
Pension balancing(4)	41,193	30,682	32,541
Income taxes	44,767	49,007	47,427
Pension and other postretirement benefit liabilities	189,111	118,485	201,845
Environmental costs(2)	37,443	51,861	58,859
Gas costs	2,098	1,936	5,971
Other(3)	15,801	10,799	18,750
Total non-current	$333,953	$263,321	$368,908

	Regulatory Liabilities		
	September 30,		December 31,
In thousands	2015	2014	2014
Current:			
Gas costs	$22,499	$6,704	$5,700
Unrealized gain on derivatives(1)	2,939	5,320	240
Other(3)	8,689	11,328	13,165
Total current	$34,127	$23,352	$19,105
Non-current:			
Gas costs	$6,357	$410	$2,507
Unrealized gain on derivatives(1)	299	602	—
Accrued asset removal costs(5)	324,467	307,815	311,238
Other(3)	3,367	3,673	3,460
Total non-current	$334,490	$312,500	$317,205

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) Environmental costs relate to specific sites approved for regulatory deferral by the Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC). In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. The current portion of environmental assets represents deferred costs to be recovered in Oregon rates beginning November 1, 2015. See Note 13.

(3)

These balances primarily consist of deferrals and amortizations under approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(4) The deferral of certain pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower net

7

Table of Contents

periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of interest income recognized when amounts are collected in rates.

(5) Estimated costs of removal on certain regulated properties are collected through rates. See Note 2 of the 2014 Form 10-K.

Environmental Regulatory Accounting

On February 20, 2015 the OPUC issued an Order addressing outstanding implementation items related to the Site Remediation and Recovery Mechanism (SRRM). Under the Order, $15 million of $95 million in total environmental remediation expenses deferred through 2012 were disallowed. The OPUC found the $95 million to be prudent but disallowed this amount from rate recovery based on its determination of how an earnings test should apply to years between 2003 and 2012, with adjustments for other factors the OPUC deemed relevant. We recognized the $15 million pre-tax disallowance, or $9.1 million after-tax charge, during the first quarter of 2015. The charge was recorded in operations and maintenance expense. As a result of the order, we recognized $5.3 million pre-tax of interest income related to the equity earnings on our deferred environmental expenses. See Note 13.

New Accounting Standards

Recent Accounting Pronouncements

We consider the applicability and impact of all accounting standards updates (ASUs) issued by the Financial Accounting Standards Board (FASB). Accounting standards updates not listed below were assessed and determined to be either not applicable or are expected to have minimal impact on our consolidated financial position or results of operations.

BENEFIT PLAN ACCOUNTING. On July 31, 2015, the FASB issued ASU 2015-12, Plan Accounting: Defined Benefit Pension Plans, Defined Contribution Pension Plans, and Health and Welfare Benefit Plans. The ASU outlines a three part update. Only part two of the update applies to the Company, which simplifies the investment disclosure requirements for employee benefit plans by allowing certain disclosures at an aggregated level, reducing the number of ways assets must be grouped and analyzed, and no longer requiring investment strategy disclosures for certain investments. The new requirements are effective for the Company beginning January 1, 2016, with early adoption permitted. We will be required to apply the disclosure guidance retrospectively and do not expect the ASU to materially affect our financial statements and disclosures.

FAIR VALUE MEASUREMENT. On May 1, 2015, the FASB issued ASU 2015-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent). The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements are effective for the Company beginning January 1, 2016 with retrospective application to all periods presented required and early adoption permitted. We do not expect the ASU to materially affect our financial statements and disclosures.

INTANGIBLES - GOODWILL AND OTHER - INTERNAL-USE SOFTWARE. On April 15, 2015 the FASB issued ASU 2015-05, Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. The ASU provides customers guidance on how to determine whether a cloud computing arrangement includes a software license. The new requirements are effective for the Company beginning January 1, 2016. The ASU can be applied prospectively or retrospectively and early adoption is permitted. We intend to apply the guidance prospectively and do not expect the ASU to materially affect our financial statements and disclosures.

DEBT ISSUANCE COSTS. On April 7, 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs, which requires the presentation of debt issuance costs in the balance sheet as a direct deduction from the associated debt liability. The new requirements are effective for the Company beginning January 1, 2016. Early adoption is permitted, and the new guidance will be applied on a retrospective basis. We do not expect the ASU to materially affect our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 Revenue From Contracts with Customers. The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts expected to be entitled to in exchange for those goods or services. The model provides a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance

Table of Contents

obligation is satisfied. The new requirements prescribe either a full retrospective or simplified transition adoption method. On August 12, 2015, the FASB deferred the effective date by one year to January 1, 2018 for annual reporting periods beginning after December 15, 2017. The FASB also permitted early adoption of the standard, but not before the original effective date of January 1, 2017. We are currently assessing the effect of this standard on our financial statements and disclosures.

3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted average number of common shares outstanding plus the effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Antidilutive stock options are excluded from the calculation of diluted earnings per common share. Diluted earnings (loss) per share are calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share data	2015	2014	2015	2014
Net income (loss)	$(6,685)	$(8,733)	$23,998	$30,222
Average common shares outstanding - basic	27,363	27,189	27,336	27,145
Additional shares for stock-based compensation plans outstanding	—	—	63	50
Average common shares outstanding - diluted	27,363	27,189	27,399	27,195
Earnings (loss) per share of common stock - basic	$(0.24)	$(0.32)	$0.88	$1.11
Earnings (loss) per share of common stock - diluted	$(0.24)	$(0.32)	$0.88	$1.11
Additional information:				
Antidilutive shares	91	80	19	24

4. SEGMENT INFORMATION

We primarily operate in two reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which are aggregated and reported as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes the utility portion of our Mist underground storage facility in Oregon (Mist) and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp. Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Other includes NNG Financial and NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project. See Note 4 in the 2014 Form 10-K for further discussion of our segments.

Table of Contents

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

	Three Months Ended September 30,			
In thousands	Utility	Gas Storage	Other	Total
2015				
Operating revenues	$87,475	$5,596	$57	$93,128
Depreciation and amortization	18,721	1,621	—	20,342
Income (loss) from operations	(4,088)	2,204	11	(1,873)
Net income (loss)	(7,529)	799	45	(6,685)
Capital expenditures	28,325	526	—	28,851
2014				
Operating revenues	$82,361	$4,782	$56	$87,199
Depreciation and amortization	18,279	1,659	—	19,938
Income (loss) from operations	(6,221)	926	218	(5,077)
Net income (loss)	(8,808)	2	73	(8,733)
Capital expenditures	33,717	346	—	34,063

	Nine Months Ended September 30,			
In thousands	Utility	Gas Storage	Other	Total
2015				
Operating revenues	$476,672	$16,232	$169	$493,073
Depreciation and amortization	55,798	4,885	—	60,683
Income from operations	59,955	3,998	89	64,042
Net income	23,051	827	120	23,998
Capital expenditures	84,598	2,325	—	86,923
Total assets at September 30, 2015	2,693,953	269,289	15,123	2,978,365
2014				
Operating revenues	$495,931	$17,655	$168	$513,754
Depreciation and amortization	54,333	4,903	—	59,236
Income from operations	78,971	3,994	252	83,217
Net income	29,416	472	334	30,222
Capital expenditures	85,793	759	—	86,552
Total assets at September 30, 2014	2,539,834	277,689	16,001	2,833,524
Total assets at December 31, 2014	$2,775,011	$273,813	$16,121	$3,064,945

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes and the associated cost of gas. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. By subtracting cost of gas from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The gas storage segment and other emphasize growth in operating revenues as opposed to margin because they do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

Table of Contents

The following table presents additional segment information concerning utility margin:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2015	2014	2015	2014
Utility margin calculation:				
Utility operating revenues	$87,475	$82,361	$476,672	$495,931
Less: Utility cost of gas	35,856	32,227	223,737	245,708
Utility margin	$51,619	$50,134	$252,935	$250,223

5. STOCK-BASED COMPENSATION

Our stock-based compensation plans include a Long-Term Incentive Plan (LTIP) under which various types of equity awards may be granted. For additional information on our stock-based compensation plans, see Note 6 in the 2014 Form 10-K and the updates provided below.

Long-Term Incentive Plan

Performance-Based Stock Awards

LTIP performance shares incorporate a combination of market, performance, and service-based factors. During the nine months ended September 30, 2015, 47,550 performance-based shares were granted under the LTIP based on target-level awards with a weighted-average grant date fair value of $51.85 per share. As of September 30, 2015, there was $2.6 million of unrecognized compensation cost from LTIP grants, which is expected to be recognized through 2017. Fair value for the market based portion of the LTIP 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	$47.64	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.465	
Expected dividend yield	3.8	%
Dividend discount factor	0.8966	

Performance-Based Restricted Stock Units (RSUs)

During the nine months ended September 30, 2015, 37,264 RSUs were granted under the LTIP with a weighted-average grant date fair value of $46.28 per share. The fair value of a RSU is equal to the closing market price of our common stock on the grant date. As of September 30, 2015, there was $2.9 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2019. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU.

6. DEBT

Short-Term Debt

At September 30, 2015, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 71 days, an average maturity of 62 days, and an outstanding balance of $225.2 million. The carrying cost of our commercial paper approximates fair value using Level 2 inputs due to the short-term nature of the notes. See Note 2 in the 2014 Form 10-K for a description of the fair value hierarchy.

Long-Term Debt

At September 30, 2015, our utility segment had long-term debt of $601.7 million. Utility long-term debt consists of first mortgage bonds (FMBs) with maturity dates ranging from 2016 through 2042, interest rates ranging from 3.176% to 9.05%, and a weighted-average coupon rate of 5.70%. The utility redeemed $40 million of FMBs with a coupon rate of 4.70% in June 2015.

Table of Contents

At September 30, 2015, our gas storage segment's long-term debt consisted of $20 million of fixed-rate senior collateralized debt with a maturity date of November 30, 2016 and an interest rate of 7.75%. This debt is collateralized by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural.

On April 28, 2015, Gill Ranch entered into an amendment to the loan agreement under which the earnings before interest, tax, depreciation, and amortization (EBITDA) covenant requirement is suspended through maturity of the loan. Previously, the covenant had been suspended through March 31, 2015, and the debt service reserve was set at $3 million. Under the amendment, the debt service reserve was fixed at $4.5 million as of June 30, 2015 with scheduled increases by contributions of $1.5 million on each of January 30, 2016 and August 30, 2016, respectively. Additionally, Gill Ranch must receive common equity contributions from its parent NWN Gas Storage of at least $2 million by August 31, 2015, which was made on May 19, 2015, and of at least $4 million by August 31, 2016.

Fair Value of Long-Term Debt

Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2 in the 2014 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,
In thousands	2015	2014	2014
Carrying amount	$621,700	$661,700	$661,700
Estimated fair value	697,647	748,902	756,808

See Note 7 in the 2014 Form 10-K for additional information regarding our long-term debt.

7. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

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

	Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2015	2014	2015	2014
Service cost	$2,308	$1,919	$145	$136
Interest cost	4,597	4,511	291	309
Expected return on plan assets	(5,174)	(4,887)	—	—
Amortization of net actuarial loss	4,561	2,579	125	46
Amortization of prior service costs	57	56	50	50
Net periodic benefit cost	6,349	4,178	611	541
Amount allocated to construction	(2,061)	(1,242)	(218)	(177)
Amount deferred to regulatory balancing account(1)	(2,171)	(1,107)	—	—
Net amount charged to expense	$2,117	$1,829	$393	$364

Table of Contents

	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2015	2014	2015	2014
Service cost	$6,926	$5,755	$435	$407
Interest cost	13,787	13,535	874	928
Expected return on plan assets	(15,522)	(14,659)	—	—
Amortization of net actuarial loss	13,683	7,739	376	138
Amortization of prior service costs	173	168	148	148
Net periodic benefit cost	19,047	12,538	1,833	1,621
Amount allocated to construction	(5,765)	(3,644)	(607)	(518)
Amount deferred to regulatory balancing account[1]	(6,511)	(3,331)	—	—
Net amount charged to expense	$6,771	$5,563	$1,226	$1,103

(1) The deferral of defined benefit pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account. The balancing account includes the expectation of higher net periodic benefit costs than costs recovered in rates in the near-term with lower net periodic benefit costs than costs recovered in rates expected in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest recognized when amounts are collected in rates.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2015	2014	2015	2014
Beginning balance	$(9,413)	$(6,027)	$(10,076)	$(6,358)
Amounts reclassified from AOCL:				
Amortization of prior service costs	—	(1)	—	(5)
Amortization of actuarial losses	549	275	1,645	826
Total reclassifications before tax	549	274	1,645	821
Tax expense	(217)	(108)	(650)	(324)
Total reclassifications for the period	332	166	995	497
Ending balance	$(9,081)	$(5,861)	$(9,081)	$(5,861)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plan

For the nine months ended September 30, 2015, we made cash contributions totaling $11.8 million to the qualified defined benefit pension plan. We expect further plan contributions of $2.3 million during the remainder of 2015.

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 $2.9 million and $2.8 million for the nine months ended September 30, 2015 and 2014, respectively.

See Note 8 in the 2014 Form 10-K for more information concerning these retirement and other postretirement benefit plans.

Table of Contents

8. INCOME TAX

An estimate of annual income tax expense is made each interim period using estimates for annual pre-tax income, regulatory flow-through adjustments, tax credits, and other items. The estimated annual effective tax rate is applied to year-to-date, pre-tax income to determine income tax expense for the interim period consistent with the annual estimate.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dollars in thousands	2015	2014	2015	2014
Income tax at statutory rates (federal and state)	$(4,473)	$(6,161)	$15,848	$20,288
Increase (decrease):				
Differences required to be flowed-through by regulatory commissions	(378)	(310)	1,036	1,184
Other, net	298	(271)	(940)	(449)
Income tax expense (benefit)	$(4,553)	$(6,742)	$15,944	$21,023
Effective income tax rate	40.5%	43.6%	39.9%	41.0%

Increases or decreases in income tax expense are correlated with changes in pre-tax income. The effective tax rate for the three and nine months ended September 30, 2015, compared to the same periods in 2014, decreased primarily as a result of depletion deductions from gas reserves activity. Additionally, there was a comparative decrease due to a $0.6 million income tax charge in the first quarter of 2014 due to the revaluation of deferred tax balances related to a higher effective tax rate in Oregon. See Note 9 in the 2014 Form 10-K for more detail on income taxes and effective tax rates.

Our examination under the Internal Revenue Service (IRS) Compliance Assurance Process for the 2013 tax year was completed during the first quarter of 2015. The examination did not result in a material change to the return as originally filed.

9. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and related accumulated depreciation:

	September 30,		December 31,
In thousands	2015	2014	2014
Utility plant in service	$2,710,658	$2,655,136	$2,661,097
Utility construction work in progress	58,280	31,778	24,886
Less: Accumulated depreciation	867,281	850,590	836,510
Utility plant, net	1,901,657	1,836,324	1,849,473
Non-utility plant in service	296,169	297,199	297,295
Non-utility construction work in progress	7,891	6,549	9,282
Less: Accumulated depreciation	37,856	32,978	34,457
Non-utility plant, net	266,204	270,770	272,120
Total property, plant, and equipment	$2,167,861	$2,107,094	$2,121,593
Capital expenditures in accrued liabilities	$9,700	$11,834	$8,757

14

Table of Contents

10. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field as of September 30, 2015. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Our investment in gas reserves provides long-term price protection for utility customers and currently incorporates two agreements: the original agreement with Encana Oil & Gas (USA) Inc. under which we invested $178 million and the amended agreement with Jonah Energy LLC under which an additional $10 million was invested.

We entered into our original agreements with Encana in 2011 under which we hold working interests in certain sections of the Jonah Field. Gas produced in these sections is sold at prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to the utility's cost of gas. The cost of gas, including a carrying cost for the rate base investment, is included in NW Natural's annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return.

In March 2014, we amended the original gas reserves agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field. We also retained the right to invest in new wells with Jonah Energy. The amended agreements allow us to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, and may have the opportunity to participate in more wells in the future.

We filed an application requesting regulatory deferral in Oregon for these additional investments, which was granted in April 2015. Accordingly, we filed in 2015 seeking cost recovery for the additional wells drilled in 2014. In September 2015, the OPUC adopted an all-party settlement, under which volumes produced are included in our Oregon PGA beginning November 1, 2015 at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

The following table outlines our net investment in gas reserves:

In thousands	September 30, 2015	2014	December 31, 2014
Gas reserves, current	$17,822	$21,455	$20,020
Gas reserves, non-current	169,300	164,115	167,190
Less: Accumulated amortization	51,516	32,370	37,910
Total gas reserves[(1)]	135,606	153,200	149,300
Less: Deferred tax liabilities on gas reserves	23,042	33,037	18,551
Net investment in gas reserves[(1)]	$112,564	$120,163	$130,749

(1) Gas reserves include our investments in additional wells with Jonah Energy with the total gross investment of $9.7 million and $8.2 million at September 30, 2015 and 2014, respectively. Net investment in the additional wells was $4.5 million and $6.5 million at September 30, 2015 and 2014, respectively.

11. INVESTMENTS

Equity Method Investments

Trail West Pipeline, LLC (TWP), a wholly-owned subsidiary of TWH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with the utility distribution system. NWN Energy, a wholly-owned subsidiary of NW Natural owns 50% of TWH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Table of Contents

VIE Analysis

TWH is a Variable Interest Entity, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH's activities, as we only have a 50% share of the entity and there are no stipulations that allow us a disproportionate influence over it. Our investment in TWH and TWP is included in other investments on our balance sheet. If we do not develop this investment, then the maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to it as a 50% owner. Our investment balance in TWH was $13.4 million at September 30, 2015 and 2014 and December 31, 2014. See Note 12 in the 2014 Form 10-K.

Other Investments

Other investments include financial investments in life insurance policies, which are accounted for at cash surrender value, net of policy loans. See Note 12 in the 2014 Form 10-K.

12. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to hedge a portion of the utility's natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

We enter into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to our physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of utility customers. These contracts qualify for regulatory deferral accounting treatment.

We also enter into exchange contracts related to the third-party asset management of our gas portfolio, some of which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement. These derivatives are recognized in operating revenues in our gas storage segment, net of amounts shared with utility customers.

Notional Amounts

The following table presents the absolute notional amounts related to open positions on our derivative instruments:

In thousands	September 30, 2015	2014	December 31, 2014
Natural gas (in therms):			
Financial	416,075	368,425	287,475
Physical	521,350	620,550	420,980
Foreign exchange	$8,023	$10,296	$12,230

Purchased Gas Adjustment (PGA)

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. Derivative contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon, which provides for either an 80% or 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 20% or 10%, respectively, recognized in current income. For the 2014-15 and 2015-16 gas years, we selected the 90% and 80% deferral option, respectively. In general, our commodity hedging for the current gas year is completed prior to the start of the upcoming gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. As of November 1, 2014, we reached our target hedge percentage of approximately 75% for the 2014-15 gas year. These hedge prices were included in the PGA filings and qualified for regulatory deferral.

Table of Contents

Unrealized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments:

	Three Months Ended September 30,			
	2015		2014	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Expense to cost of gas	$(8,415)	$(150)	$(10,173)	$(421)
Operating revenues	33	—	—	—
Less:				
Amounts deferred to regulatory accounts on the balance sheet	8,391	150	10,559	421
Total gain in pre-tax earnings	$9	$—	$386	$—

	Nine Months Ended September 30,			
	2015		2014	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
(Expense) benefit to cost of gas	$(21,876)	$(413)	$360	$(242)
Operating revenues	55	—	—	—
Less:				
Amounts deferred to regulatory accounts on the balance sheet	21,838	413	(93)	242
Total gain in pre-tax earnings	$17	$—	$267	$—

Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward contracts and natural gas derivative contracts are recognized immediately in cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

Realized Gain/Loss

We realized a net loss of $2.3 million and $24.3 million for the three and nine months ended September 30, 2015 and a net gain of $0.5 million and $13.3 million for the three and nine months ended September 30, 2014, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivative Instruments

No collateral was posted with, or by, our counterparties as of September 30, 2015 or 2014. 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 2014 or 2015. 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 on current financial swap and option contracts outstanding, which reflect net unrealized losses of $23.8 million at September 30, 2015, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings)	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative

	A+/A3				
With Adequate Assurance Calls	$—	$—	$—	$—	$22,066
Without Adequate Assurance Calls	—	—	—	—	15,937

17

Table of Contents

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our statement of financial position. We and our counterparties have the ability to set-off our obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by each counterparty, our net derivative position would result in an asset of $3.1 million and a liability of $25.3 million as of September 30, 2015. As of September 30, 2014, our derivative position would have resulted in an asset of $4.0 million and a liability of $3.9 million, and as of December 31, 2014, our derivative position would have resulted in an asset of $0.2 million and a liability of $33.4 million.

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 natural gas purchases made on behalf of customers. See Note 13 in the 2014 Form 10-K for additional information.

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 models 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, 2015. As of September 30, 2015 and 2014 and December 31, 2014, the net fair value was a liability of $22.2 million, an asset of $0.1 million, and a liability of $33.2 million, respectively, using significant other observable, or Level 2, inputs. No Level 3 inputs were used in our derivative valuations, and there were no transfers between Level 1 or Level 2 during the nine months ended September 30, 2015 and 2014.

13. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Due to the numerous uncertainties surrounding the course of environmental remediation and the ongoing nature of several site investigations, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated. Unless there is an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations, and the determination by regulators of remediation alternatives.

In Oregon, we have a Site Remediation and Recovery Mechanism (SRRM) through which we track and have the ability to recover past deferred and future environmental remediation costs, subject to an earnings test. An Order from the OPUC in February 2015 deemed certain environmental remediation expenses and associated carrying costs deferred through March 31, 2014 prudent. Our settlement with insurance carriers resulting in insurance proceeds received was also deemed prudent in the Order. Under the Order, we were required to forgo the collection of $15 million out of approximately $95 million of environmental remediation expenses and associated carrying costs we had deferred through 2012 under the Order. The OPUC disallowed this amount from rate recovery based on its determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. See Note 2 for information regarding the regulatory disallowance of past deferred costs under the Order received from the OPUC in February 2015.

We received total environmental insurance proceeds of approximately $150 million as a result of settlements from our litigation that was dismissed in July 2014. Under the OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012, and the remaining two-thirds will be applied to costs over the next 20 years.

Table of Contents

Under the SRRM, we will recover the first $5 million of annual expense through an amount that will be collected from Oregon customers through a tariff rider. We will apply $5 million of insurance (plus interest) to the next portion of environmental expenses each year. Any expenses and interest on expenses in excess of the annual $10 million (plus interest from insurance) are fully recoverable through the SRRM, to the extent the utility earns at or below our authorized Return On Equity (ROE). To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10 million (plus interest from insurance proceeds) with those earnings that exceed its authorized ROE.

We submitted the required compliance filing demonstrating the proposed implementation of the Order and SRRM in March 2015. In September 2015, as a result of discussions with the parties, we withdrew our original compliance filing and submitted a revised filing noting the parties could potentially raise two issues with our proposed implementation of the Order. First, we believe the February 2015 Order reflected the Commission’s determination of the total disallowance to be borne by NW Natural for prior periods; however, we anticipate the parties will question whether interest on the $15 million charge should be separately disallowed. This interest would total approximately $3 million. Second, we anticipate discussions concerning how state allocation rates from the Order are applied to our environmental remediation sites. However, we believe the effect on current regulatory deferrals related to the state allocation issue would be insignificant.

We are engaged in the Commission’s process with the parties to resolve issues they have raised regarding the compliance filing and expect resolution of these matters in the first half of 2016. The revised compliance filing is subject to final review and approval by the OPUC and as a consequence thereof, additional or different implementation procedures could be required, which may, among other things, result in additional impacts on earnings.

In addition, we requested clarification from the OPUC regarding the amount of Oregon-allocated insurance proceeds to be held in a secured account. In September 2015, the OPUC resolved the issue by adopting an all-party settlement, which provided that we did not need to obtain a secured account. Instead, under the order insurance proceeds used to offset future environmental expenses will accrue interest at a rate equal to the five-year treasury rate plus 100 basis points. Currently, Oregon-allocated insurance proceeds total approximately $96 million on a pre-tax basis.

In Washington, cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. Annually, we review all regulatory assets for recoverability or more often if circumstances warrant. If we should determine all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such a determination is made.

Table of Contents

Environmental Sites

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

	Current Liabilities			Non-Current Liabilities		
	September 30,		December 31,	September 30,		December 31,
In thousands	2015	2014	2014	2015	2014	2014
Portland Harbor site:						
Gasco/Siltronic Sediments	$1,236	$686	$1,767	$38,533	$38,593	$38,019
Other Portland Harbor	1,243	1,060	1,934	4,563	3,198	4,338
Gasco site	4,510	7,399	9,535	36,795	37,748	37,117
Siltronic Uplands site	538	634	957	489	577	348
Central Service Center site	177	70	171	—	173	—
Front Street site	420	804	1,020	215	99	122
Oregon Steel Mills	—	—	—	179	179	179
Total	$8,124	$10,653	$15,384	$80,774	$80,567	$80,123

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

	September 30,		December 31,
In thousands	2015	2014	2014
Cumulative cash paid	$121,819	$111,367	$113,740
Total regulatory asset deferral(1)	49,807	51,861	58,859

(1) Includes cash paid, remaining liability, and interest, net of insurance reimbursement and amounts reclassified to utility plant for the water treatment station.

PORTLAND HARBOR SITE. The Portland Harbor is an Environmental Protection Agency (EPA) listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to our Gasco uplands and Siltronic uplands sites. We are a potentially responsible party (PRP) to the Superfund site and have joined with some of the other PRPs (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). In August 2015, the EPA issued its own Draft Feasibility Study (Draft FS) for comment. The EPA Draft FS provides a new range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of present value costs estimated by the EPA for various remedial alternatives for the entire Portland Harbor, as provided in the EPA’s Draft FS, is $791 million to $2.45 billion. The range provided in the EPA’s Draft FS is based on cost alternatives the EPA estimates to have an accuracy between -30% and +50% of actual costs, depending on the scope of work. While the EPA’s Draft FS provides a higher range of costs than the LWG's submission, our potential liability is still a portion of the costs of the remedy the EPA will select for the entire Portland Harbor Superfund site. The cost of the remedy is expected to be allocated among more than 100 PRPs. We are participating in a non-binding allocation process in an effort to settle this potential liability. The new EPA Draft FS does not provide any additional clarification around allocation of costs. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

GASCO/SILTRONIC SEDIMENTS. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. We submitted a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA, as well as the estimated costs for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up, range from $39.8 million to $350 million. We have recorded a liability of $39.8 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

OTHER PORTLAND HARBOR. We incur costs related to our membership in the LWG, who is performing the RI/FS for the EPA, and also incur costs related to natural resource damages from these sites. NW Natural and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. Natural resource damage claims may arise only after a remedy for clean-up has been settled. We have accrued a liability for these claims at the low end of the range of the potential liability; the high end of the range cannot be reasonably estimated at this time. This liability is not included in the range of costs provided in the EPA Draft FS for the Portland Harbor noted above.

GASCO SITE. We own a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by NW Natural for environmental contamination under the Oregon Department of Environmental Quality (ODEQ) Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site noted above. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

Uplands. In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and it was approved by the ODEQ in March 2010. In 2015, ODEQ approved a risk assessment for the Uplands site, and we are currently working on a feasibility study. We have recognized a liability for the remediation of the uplands portion of the site at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

Groundwater Source Control. In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We are working with ODEQ on monitoring the effectiveness of the system and at this time it is unclear what, if any, additional actions ODEQ may require subsequent to the performance testing of the system or as part of the final remedy for the uplands portion of the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability at the low end of the range of potential cost. We cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which will be highly dependent upon the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

Beginning November 1, 2013, capital asset costs of $19 million for the Gasco water treatment station were placed into rates with OPUC approval. The OPUC deemed these costs prudent. Beginning November 1, 2014, the OPUC approved the application of $2.5 million from insurance proceeds plus interest to reduce the total amount of Gasco capital costs to be recovered through rate base.

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

Siltronic Upland site. A portion of the Siltronic property was formerly part of the Gasco site. We are currently conducting an investigation of manufactured gas plant wastes on the uplands portion of this site for the ODEQ.

Central Service Center site. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. This site is on ODEQ's list of sites with confirmed releases of hazardous substances requiring cleanup.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. At ODEQs request, we conducted a sediment and source control investigation and provided findings to ODEQ. A Feasibility Study is currently underway.

Oregon Steel Mills site. See “Legal Proceedings,” below.

Table of Contents

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 the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations, or cash flows. See also Part II, Item 1, “Legal Proceedings.”

OREGON STEEL MILLS SITE. In 2004, we were 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 the ultimate disposition of this matter will have a material effect on our financial condition, results of operations, or cash flows.

For additional information regarding other commitments and contingencies, see Note 14 in the 2014 Form 10-K.

Table of Contents

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

The following is management’s assessment of Northwest Natural Gas Company’s (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The disclosures contained in this report refer to our consolidated activities for the three and nine months ended September 30, 2015 and 2014. References to “Notes” are to the Notes to Unaudited 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 the three and nine month periods are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2014 Annual Report on Form 10-K (2014 Form 10-K).

The consolidated financial statements include NW Natural, the parent company, and its direct and indirect wholly-owned subsidiaries.

We operate in two primary reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment includes our NW Natural local gas distribution business, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist (NWN's storage facility in Oregon), and asset management services. Other includes NWN Energy's equity investment in Trail West Holdings, LLC (TWH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Trail West Pipeline, LLC (TWP), and NNG Financial's equity investment in Kelso-Beaver Pipeline (KB Pipeline). For a further discussion of our business segments and other, see Note 4.

In addition to presenting the results of operations and earnings amounts in total, certain financial measures are expressed in cents per share or exclude the after-tax regulatory disallowance related to the OPUC's 2015 environmental order, which are non-GAAP financial measures. We present net income and earnings per share (EPS) excluding the regulatory disallowance along with the U.S. GAAP measures to illustrate the magnitude of this disallowance on ongoing business and operational results. Although the excluded amounts are properly included in the determination of net income and earnings per share under U.S. GAAP, we believe the amount and nature of such disallowance make period to period comparisons of operations difficult or potentially confusing. Financial measures are expressed in cents per share as these amounts reflect factors that directly impact earnings, including income taxes. All references in this section to EPS are on the basis of diluted shares (see Note 3). We use such non-GAAP measures to analyze our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

Table of Contents

EXECUTIVE SUMMARY

Consolidated results for the quarter include:

	Three Months Ended September 30,				
	2015		2014		
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net loss	$(6,685)	$(0.24)	$(8,733)	$(0.32)	$2,048
Utility margin	51,619		50,134		1,485
Gas storage operating revenues	5,596		4,782		814

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Consolidated net loss was $2.0 million lower primarily due to a $1.5 million increase in utility margin, a $0.8 million increase in gas storage operating revenues, a $0.9 million decrease in operations and maintenance expense, and a $0.7 million decrease in interest expense.

Consolidated results for the year include:

	Nine Months Ended September 30,				
	2015		2014		
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net income	$23,998	$0.88	$30,222	$1.11	$(6,224)
Adjustments:					
Regulatory environmental disallowance, net of taxes $5,925[(1)]	9,075	0.33	—	—	9,075
Adjusted consolidated net income[(1)]	$33,073	$1.21	$30,222	$1.11	$2,851
Utility margin	$252,935		$250,223		$2,712
Gas storage operating revenues	16,232		17,655		(1,423)

(1) Regulatory environmental disallowance of $15 million is recorded in utility operations and maintenance expense. Adjusted EPS and net income are non-GAAP measures based on the after-tax disallowance. EPS is calculated using the combined federal and state statutory tax rate of 39.5% and 27.4 million dilutive shares for the first nine months of 2015.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Consolidated net income decreased $6.2 million primarily due to the $9.1 million after-tax charge related to the regulatory disallowance associated with a February 2015 OPUC Order in our SRRM docket. Under the Order, we were required to forego collection of $15 million, pre-tax, out of the approximate $95 million of environmental expenditures and associated carrying costs deferred through 2012. This charge is reflected in operations and maintenance expense. Excluding the charge, other factors affecting net income were a $2.7 million increase in utility margin, a $4.9 million increase in other income, and a $3.0 million decrease in interest expense, offset by a $1.4 million decrease in gas storage revenues and a $3.4 million increase in operations and maintenance expense.

We continued to make progress on several key strategic metrics and initiatives, as evidenced by the following items:

- added more than 10,500 customers over the past twelve months ended September 30, 2015 and increased our customer growth rate in the core utility to 1.5% from 1.3% at September 30, 2014;
- ranked first in residential customer satisfaction for large gas utilities in the West in the 2015 J.D. Power and Associates Study, making 2015 the 14th consecutive year of top three scores;
- decreased residential customer rates approximately 7% in Oregon and 14% in Washington with the 2015-16 PGA effective November 1, 2015;
- announced a dividend increase in the fourth quarter, which reflects the 60th consecutive year of increases; and
- continued land permitting and acquisition work to further the North Mist gas storage expansion project.

Table of Contents

Dividends

Dividend highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,		QTR	YTD
Per common share	2015	2014	2015	2014	Change	Change
Dividends paid	$0.465	$0.460	$1.395	$1.380	$0.005	$0.015

The Board of Directors declared a quarterly dividend on our common stock of $0.4675 per share, payable on November 13, 2015, to shareholders of record on October 30, 2015, reflecting an indicated annual dividend rate of $1.87 per share.

ISSUES AND CHALLENGES

ECONOMY. The local, national, and global economies continue to show signs of improvement. The unemployment rate in the Portland metropolitan region decreased to just over 5% during the third quarter of 2015, a decrease of about 1% from the same period in 2014. The utility's customer base is approximately 707,000 customers, reflecting a growth rate of 1.5% on a trailing 12-month basis at September 30, 2015, up from 1.3% at September 30, 2014. We continue to believe our utility is well positioned to add customers and serve increasing demand as the economy improves and gas prices remain low, as regional business projects move forward, and legislation focused on lowering carbon emissions continues to develop.

GAS PRICES, SUPPLIES, AND STORAGE VALUES. Our utility gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our customers and to manage gas prices. Our utility's annual PGA mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure and secure more stable gas costs for customers. We typically hedge gas prices on approximately 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2014-15 gas year (November 1, 2014 – October 31, 2015) hedged at approximately 75% of our forecasted sales volumes, including 41% in financial swap and option contracts, 22% in physical gas supplies, and 12% in gas reserves. For further discussion see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" below.

In addition to the amount hedged for the current gas contract year, we were hedged at approximately 70% for the upcoming 2015-16 gas year and between 6% and 15% for the following five gas years as of September 30, 2015. Our hedge levels are based on estimated sales volumes, which depend, to a certain extent, on weather and economic conditions. Our gas reserves amounts may increase or decrease depending on production and investment levels. Also, our gas storage inventory levels may increase or decrease depending on future storage expansions, changes in storage contracts with third parties, and future storage recall by the utility pursuant to our utility's integrated resource plan.

While low and stable gas prices provide opportunities to lower costs for our utility customers, they also present challenges for our gas storage business by lowering the price of, and reducing the demand for, storage services, particularly at our Gill Ranch facility. Our Mist facility benefits from a more constrained regional supply system in the Pacific Northwest region and is impacted, to a lesser extent, by market fluctuations. Despite current market conditions, we continue to believe in the long-term need for gas storage in and around California and anticipate improvement in gas storage values driven by California's renewable portfolio standards and carbon reduction targets.

Gill Ranch storage contracts for the 2014-15 gas storage year were at historically low prices due to the flat natural gas price curve and generally weak market conditions, which negatively impacted our financial results. While prices for the 2015-16 gas year showed some improvement; they still remain low relative to the pricing in our original long-term contracts. We will begin contracting for the 2016-17 storage year in the fourth quarter of 2015 and continue to expect shorter contract lengths and prices reflecting current market trends. We are continuing to focus on lowering our operating costs, finding opportunities in the market to increase revenues through enhanced services for storage customers, and capitalizing on market opportunities that fit our business-risk profile. Future increases in the demand for natural gas or a decrease in supply could improve the market value for gas storage. Similarly, a decrease in future demand and an increase in supply could cause downward pressure on storage prices. See "Results of Operations—Business Segments—Gas Storage".

Table of Contents

ENVIRONMENTAL COSTS. We accrue estimates for environmental loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the development of remediation solutions approved by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we have been allowed to defer and recover certain costs pursuant to regulatory orders, including our SRRM, as noted in "Regulatory Matters—Rate Mechanisms—Environmental Cost Deferral" below. In addition, environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding.

REGULATORY MATTERS

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, the WUTC, and the Federal Energy Regulatory Commission (FERC) with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility. At December 31, 2014, approximately 89% of our utility gas volumes and revenues are derived from Oregon customers, with the remaining 11% from Washington customers. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other rate proceedings in Oregon and Washington, but are also affected by the local economies in Oregon and Washington, the pace of customer growth in the residential, commercial, and industrial markets, and 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 "Regulatory Activities" below.

GAS STORAGE. Our gas storage businesses are subject to regulation by the OPUC, California Public Utilities Commission (CPUC), and FERC with respect to, among other matters, rates and terms of service. The OPUC and CPUC also regulate the issuance of securities and system of accounts. The OPUC and CPUC regulate intrastate storage services, and the FERC regulates interstate storage services. The OPUC and FERC use a maximum cost of service model which allows for gas storage prices to be set at or below the cost of service as approved by each agency in the latest regulatory filing. The CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2014, approximately 69% of our storage revenues were derived from operations regulated by OPUC and FERC, and approximately 31% were derived from operations regulated by CPUC.

Ongoing Regulatory Activities

The following provides a list of significant regulatory activities:

- Environmental Cost Deferral and Site Remediation and Recovery Mechanism (SRRM) - In February 2015, the OPUC issued an order regarding the SRRM for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test. We submitted the required compliance filing in March 2015 and also filed a motion for clarification regarding the amount of insurance proceeds to be held in a secured account, and in September 2015, the OPUC issued an order adopting an all-party settlement regarding the secured account. In September 2015, we withdrew our original filing after discussions with parties and submitted a revised compliance filing. The revised compliance filing is subject to review and approval by the OPUC. See "Rate Mechanisms—Environmental Cost Deferral and SRRM."
- System Integrity Program (SIP) - We filed a request to extend the SIP program in the fourth quarter of 2014. The OPUC considered our renewal request at a public meeting in March 2015 and suspended our filing and ordered additional process, including involvement of other gas utilities in the state before making a final decision. See "Rate Mechanisms—System Integrity Program" below.
- Hedging - In our most recent Integrated Resource Plan, we proposed to the OPUC that we engage in continued long-term gas hedging. The OPUC determined it wanted to consider long-term hedging along with a general review of overall hedging practices among all gas in the state. The OPUC therefore opened a new docket to discuss gas hedging

across gas utilities in Oregon. Our request for the OPUC to consider long-term hedging practices will be considered as part of this docket. The scope of the proceeding, and the process through which it will be accomplished is being developed at this time through meetings among the parties and the involvement of the OPUC.

- Interstate Storage Sharing - We received an order from the OPUC in March 2015 on their review of the current revenue sharing arrangement that allocates a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services to utility customers. The order requires a third-party cost study to be performed and the results of the cost study may initiate a new docket or the re-opening of the original docket.

Table of Contents

- Carbon Solutions Program - Oregon Senate Bill 844 (SB 844) required the OPUC to develop rules and programs to reduce carbon emissions in Oregon. In June 2015, we submitted our first project related to Combined Heat and Power (CHP) for OPUC approval. The submitted CHP program would pay owners of new commercial- and industrial-scale CHP systems for verified carbon emission reductions. SB 844 establishes a six-month review process for these programs or allows for a longer review process if agreed upon. A final decision regarding CHP is expected in the first quarter of 2016.
- Weather Normalization Mechanism (WARM) - In Oregon, WARM is applied to residential and commercial customers' bills to adjust for temperature variances from average weather. In 2015, the OPUC initiated a review of the WARM mechanism as a result of customer complaints received this year related to surcharges applied under the WARM mechanism due to the record warm weather in our service territory during the 2014-15 winter. The OPUC review is focused on ensuring the calculations were done correctly, and to assess whether any modifications are warranted. We do not currently expect this proceeding to significantly reduce the value WARM provides in mitigating the impact to the Company and customers from variations in weather, based on the scope of the proceeding that has been established by the Commission. Since its inception, WARM has resulted in a net benefit to customers, providing bill savings of approximately $9.9 million as of September 30, 2015.

Rate Mechanisms

PURCHASED GAS ADJUSTMENT. Rate changes are established annually under PGA rate filings in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases. This includes gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, a bare steel recovery program, temporary rate adjustments that amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

We filed our PGA in September 2015 and received OPUC and WUTC approval in October 2015. PGA rate changes are effective November 1, 2015. The rate changes decreased the average monthly bills of residential customers by approximately 7% and 14% in Oregon and Washington, respectively. The decrease in Oregon reflected customers' portion of adjustments for changes in wholesale natural gas costs, offset by adjustments related to the decoupling mechanism, environmental costs, and additional annual adjustments based on ongoing orders with the OPUC. Washington rates reflected the full effect of changes in wholesale natural gas costs and some additional annual adjustments based on ongoing orders with the WUTC.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. For the 2014-15 and 2015-16 gas years, we selected the 90% and 80% deferral option, respectively. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are passed on to customers through the annual PGA rate adjustment.

EARNINGS REVIEW. We are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized ROE threshold; this is a separate earnings review from the environmental earnings test. If utility earnings exceed a specific ROE threshold, 33% of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80% deferral option under the PGA, we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90% deferral option for the 2014-2015 PGA year. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For the 2014 calendar year, the ROE threshold was 10.66%. We filed the 2014 earnings test in April 2015, which was approved by the Commission in July 2015, and we were not subject to a customer refund adjustment.

GAS RESERVES. In 2011 the OPUC approved the Encana gas reserve transaction to provide long-term gas price protection for our utility customers and determined our costs under the agreement would be recovered, on an ongoing basis through our annual PGA mechanism. Gas produced from our interests is sold at then prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to our cost of gas. The cost of gas, including a carrying cost for the rate base investment, is included in

27

our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return and provides long-term price protection for our utility customers.

In March 2014, we amended the original gas reserve agreement in order to facilitate Encana's sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field and we retained the right to invest in new wells with Jonah Energy.

In 2014 we elected to participate in some of the additional wells drilled in the Jonah field under our amended gas reserves agreement with Jonah Energy and may have the opportunity to participate in more wells in the future. We filed an application requesting regulatory deferral in Oregon for these additional investments, which was granted in April 2015. In September 2015, the OPUC adopted an all-party settlement, under which volumes produced under the amended agreement are included in our Oregon PGA beginning November 1, 2015 at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

SYSTEM INTEGRITY PROGRAM. Until November of 2014, we had the approval of the OPUC for specific accounting treatment and cost recovery for our SIP, which is an integrated safety program that consolidates the bare steel replacement program, the transmission pipeline integrity management program, and the distribution integrity management program related to pipeline safety rules adopted by the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA). We recorded these costs as either capital expenditures, accumulated the costs over each 12-month period, and recovered the revenue requirement associated with these costs, subject to audit, through rate changes effective with the Oregon annual PGA. Our SIP costs were tracked into rates annually, with the first $4 million of capital costs subject to regulatory lag and annual rate-base recovery capped at $12 million. Extraordinary costs above the cap could also be approved with written consent of the OPUC staff and other interested parties and approval of the OPUC.

During 2013, the OPUC approved a temporary two-year extension, beginning in November 2012, of our capital expenditure tracking mechanism to recover capital costs related to SIP and authorized a total increase of $13.7 million above the cap during the extension period. Regulatory authority for SIP expired October 31, 2014, although the bare steel replacement portion of the mechanism remains in place until the end of 2015. We filed a request to extend the SIP program in the fourth quarter of 2014 and upon consideration of our request in March of 2015, the OPUC ordered an additional process and evaluation with other gas utilities in the state before making a final decision. In the interim, we will recover our remaining bare steel replacement costs through the 2015-16 PGA, and we expect system integrity capital costs not tracked through an SIP mechanism would be included in rate base in our next rate case.

ENVIRONMENTAL COST DEFERRAL AND SRRM. On February 20, 2015, the OPUC issued an Order regarding the SRRM for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test. The OPUC Order addressed a number of key issues including: (1) prudence of all but $33 thousand of costs incurred through March 31, 2014; (2) insurance settlements of approximately $150 million were deemed prudent with one-third of the Oregon-allocated proceeds applied to costs prior to December 31, 2012 and two-thirds to offset future environmental expenses; and (3) disallowed recovery of expenses totaling $15 million based on the OPUC's determination of how an earnings test should apply to costs for the years between 2003 and 2012, with adjustments for other factors the OPUC deemed relevant.

With respect to recovery of remediation expenses deferred after 2012: (1) We will recover the first $5 million of annual expense through a tariff rider from Oregon customers; (2) we will apply $5 million of insurance proceeds plus interest to environmental expenses each year; and (3) any expenditures and interest on expenditures above the $10 million (plus interest) described above would be fully recoverable through the SRRM, to the extent the utility earns at or below its authorized ROE. To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10 million (plus interest from insurance proceeds) with those earnings that exceed its authorized ROE.

In any year environmental expenses are less than $10 million (plus the interest on insurance), any unused tariff rider amount will offset deferred amounts otherwise collected through the SRRM and any unused insurance proceeds (plus interest) will roll forward to offset the next year’s expenses. Under the Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds three years from February 2015 or earlier if we gain greater certainty about our future remediation costs.

Table of Contents

We submitted the required compliance filing in March 2015 with the OPUC demonstrating the proposed implementation of the Order and SRRM. In September 2015, as a result of discussions with the parties, we withdrew our original compliance filing and submitted a revised filing noting the parties could potentially raise two issues with our proposed implementation of the Order. First, we believe the February 2015 Order reflected the Commission's determination of the total disallowance to be borne by NW Natural for prior periods; however, we anticipate the parties will question whether interest on the $15 million charge should be separately disallowed. This interest would total approximately $3 million. Second, we anticipate discussions concerning how state allocation rates from the Order are applied to our environmental remediation sites. However, we believe the effect on current regulatory deferrals related to the state allocation issue would be insignificant.

We are engaged in the Commission's process with the parties to resolve issues they have raised regarding the compliance filing and expect resolution of these matters in the first half of 2016. As a consequence of the review, additional or different implementation procedures could be required, which may, among other things, result in additional impacts on earnings.

In addition, we requested clarification from the OPUC regarding the amount of Oregon-allocated insurance proceeds to be held in a secured account. In September 2015, the OPUC resolved the issue by adopting an all-party settlement, which provided that we did not need to obtain a secured account. Instead, under the settlement we will accrue interest on the insurance proceeds to be used to offset future environmental expenses at an interest rate equal to the five-year treasury rate plus 100 basis points. Currently, these Oregon-allocated insurance proceeds total approximately $96 million on a pre-tax basis.

The WUTC has also previously authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This order was effective in January 2011 with cost recovery and a carrying charge to be determined in a future proceeding.

PENSION COST DEFERRAL AND PREPAID PENSION ASSET. In Oregon, we are allowed to defer annual pension expenses related to the qualified employee defined benefit pension plan. The amount deferred each period represents the difference between the annual accounting expense and the amount included and recovered in customer rates. Recovery of the deferred amounts is through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest. Future years' deferrals will depend on changes in plan assets, projected benefit liabilities based on a number of key assumptions, and pension contributions. Pension expense deferrals were $2.2 million and $6.5 million for the three and nine months ended September 30, 2015, respectively.

A prepaid pension asset docket was opened in 2013 to evaluate pension cost recovery for all utilities in Oregon. The utilities requested recovery of the financing costs incurred as a result of timing differences between cash contributions made to their pension plans and the recognition of expense. In August 2015, the OPUC issued the final Order, which confirmed the use of accounting expense for recovery of pension expense, but denied the utilities' request to include prepaid pension assets in rates. Although we will not recover the financing costs associated with the prepaid asset, we will continue collecting pension expense based on the amounts set in our 2003 Oregon general rate case and will continue deferring the difference between actual pension expense and collected expense in our pension balancing account.

CUSTOMER CREDITS FOR GAS STORAGE AND ASSET MANAGEMENT SHARING. In the second quarter of 2015, we received regulatory approval to provide an interstate storage credit of $9.6 million to our Oregon utility customers, which was reflected in their June bills. These customer credits are part of our regulatory incentive sharing mechanism related to non-utility Mist storage and asset management services. The OPUC approved and we provided an $11.4 million interstate storage credit to Oregon customers in June of 2014. The Washington portion of these credits is included with the Washington PGA.

For a discussion of other rate mechanisms, see Part II, Item 7, “Results of Operations—Regulatory Matters—Rate Mechanisms” in our 2014 Form 10-K.

Table of Contents

RESULTS OF OPERATIONS

Business Segments - Local Gas Distribution Utility Operations
Utility margin results are primarily affected by customer growth, revenues from rate-base additions, and, to a certain extent, by changes in delivered volumes due to weather and customers' gas usage patterns because a significant portion of our utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff (also called the decoupling mechanism), which adjusts utility margin up or down each month through a deferred regulatory accounting adjustment designed 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 customer bills and our utility's earnings. See "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2014 Form 10-K for more information on our decoupling and weather normalization mechanisms.

Utility segment highlights include:

In thousands, except per share data	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	QTR Change	YTD Change
Utility net income (loss)	$(7,529)	$(8,808)	$23,051	$29,416	$1,279	$(6,365)
EPS - utility segment	$(0.28)	$(0.32)	$0.84	$1.08	$0.04	$(0.24)
Gas sold and delivered (therms)	154,664	152,329	692,527	766,799	2,335	(74,272)
Utility margin[1]	$51,619	$50,134	$252,935	$250,223	$1,485	$2,712

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

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Utility net loss was $1.3 million lower due to the following:

- a $1.5 million increase in utility margin primarily due to:
  - a $0.9 million increase from customer growth, added loads under higher commercial rate schedules, and rate-base returns on certain investments; and
  - a $0.5 million increase from gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA.
- a $0.6 million decrease in operations and maintenance expense primarily due to less contract work expense;
- a $0.7 million decrease in interest expense due to the redemption of long-term utility debt totaling $50 million since the beginning of September 2014; and
- a $0.3 million net negative impact from the following offsetting items: an increase in depreciation expense, a decrease in other income, and a decrease in general tax expense.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Utility net income decreased $6.4 million due to the following:

- the $15 million pre-tax charge, or $9.1 million after-tax charge, for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals. This charge is reflected in operations and maintenance expense;
- a $2.7 million increase in utility margin primarily due to:
  - a $4.0 million increase from customer growth in residential and commercial customers, added loads under higher commercial rate schedules, and rate-base returns on certain investments;

a $4.3 million increase from gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA; offset by

an approximate $4 million decrease due to lower customer usage from warmer weather, which impacts utility margins from our Washington customers where we do not have a weather normalization mechanism in place, and from our Oregon customers who opted out of weather normalization; and

a $1.7 million decrease from a number of other items primarily related to cost deferrals.

- a $4.8 million increase in other income primarily due to the recognition of the equity earnings on deferred environmental expenditures as a result of the February order;
- a $2.1 million decrease in interest expense due to the redemption of long-term utility debt;

30

Table of Contents

- a $4.7 million increase in operations and maintenance expense primarily due to an increase in compensation and benefit expense;
- a $1.5 million increase in depreciation expense primarily due to planned capital expenditures; and
- a $0.7 million increase in general tax expense primarily due to increases in Oregon property tax expense.

Total utility volumes sold and delivered in the three months ended September 30, 2015 increased 2% due to greater customer usage and customer growth compared to the same period in 2014. For the nine months ended September 30, 2015, volumes decreased 10% compared to the nine months ended September 30, 2014 due to the impact of 15% warmer weather.

UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes, revenues, and costs of gas:

In thousands, except degree day and customer data	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014	Favorable/ (Unfavorable) QTD	YTD
Utility volumes (therms):						
Residential and commercial sales	53,662	49,843	357,545	420,532	3,819	(62,987)
Industrial sales and transportation	101,002	102,486	334,982	346,267	(1,484)	(11,285)
Total utility volumes sold and delivered	154,664	152,329	692,527	766,799	2,335	(74,272)
Utility operating revenues:						
Residential and commercial sales	$73,236	$68,369	$432,067	$451,557	$4,867	$(19,490)
Industrial sales and transportation	15,959	15,588	53,623	53,955	371	(332)
Other revenues	651	602	3,188	3,245	49	(57)
Less: Revenue taxes	2,371	2,198	12,206	12,826	173	(620)
Total utility operating revenues	87,475	82,361	476,672	495,931	5,114	(19,259)
Less: Cost of gas	35,856	32,227	223,737	245,708	3,629	(21,971)
Utility margin	$51,619	$50,134	$252,935	$250,223	$1,485	$2,712
Utility margin:(1)						
Residential and commercial sales	$43,312	$42,267	$225,624	$226,839	$1,045	$(1,215)
Industrial sales and transportation	7,233	6,962	22,065	22,153	271	(88)
Miscellaneous revenues	647	684	3,186	3,550	(37)	(364)
Gain (loss) from gas cost incentive sharing	431	(84)	1,992	(2,345)	515	4,337
Other margin adjustments	(4)	305	68	26	(309)	42
Utility margin	$51,619	$50,134	$252,935	$250,223	$1,485	$2,712
Degree days:						
Average(2)	95	95	2,641	2,641	—	—
Actual degree days	75	18	2,068	2,438	317%	(15)%
Percent colder (warmer) than average weather(2)	(21)%	(81)%	(22)%	(8)%		

	As of September 30,			
Customers - end of period:	2015	2014	Change	% Change
Residential customers	640,313	629,627	10,686	1.7 %
Commercial customers	65,305	65,337	(32)	—
Industrial customers	948	938	10	1.1
Total number of customers	706,566	695,902	10,664	1.5 %

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

(2) Average weather represents the 25-year average degree days, as determined in our 2012 Oregon general rate case.

31

Table of Contents

Residential and Commercial Sales

Residential and commercial sales highlights include:

In thousands	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	QTR Change	YTD Change
Utility volumes (therms):						
Residential sales	28,303	26,235	215,018	255,471	2,068	(40,453)
Commercial sales	25,359	23,608	142,527	165,061	1,751	(22,534)
Total volumes	53,662	49,843	357,545	420,532	3,819	(62,987)
Utility operating revenues:						
Residential sales	$44,721	$41,907	$281,033	$294,119	$2,814	$(13,086)
Commercial sales	28,515	26,462	151,034	157,438	2,053	(6,404)
Total operating revenues	$73,236	$68,369	$432,067	$451,557	$4,867	$(19,490)
Utility margin:						
Residential:						
Sales	$27,647	$26,341	$138,187	$154,293	$1,306	$(16,106)
Weather normalization adjustments	—	—	12,492	489	—	12,003
Decoupling adjustments	1,149	1,738	5,318	2,145	(589)	3,173
Total residential utility margin	28,796	28,079	155,997	156,927	717	(930)
Commercial:						
Sales	12,736	12,180	56,997	64,487	556	(7,490)
Weather normalization adjustments	(2)	—	5,213	296	(2)	4,917
Decoupling adjustments	1,782	2,008	7,417	5,129	(226)	2,288
Total commercial utility margin	14,516	14,188	69,627	69,912	328	(285)
Total utility margin	$43,312	$42,267	$225,624	$226,839	$1,045	$(1,215)

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Residential and commercial utility variances were as follows:

- sales volumes increased 3.8 million therms primarily due to greater customer usage and customer growth during the quarter;
- operating revenues increased $4.9 million primarily due to a 7% increase in average cost of gas; and
- utility margin increased $1.0 million due to increases from commercial and residential customer growth, added loads under higher commercial rate schedules, and added rate-base returns on certain investments.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Residential and commercial utility variances were as follows:

- sales volumes decreased 63.0 million therms primarily due to 15% warmer weather compared to prior year;
- operating revenues decreased $19.5 million primarily due to 15% warmer weather, partially offset by a 6% increase in average cost of gas; and
- utility margin decreased $1.2 million primarily due to the effects of warmer weather on customers not covered by a weather normalization mechanism. The effect of weather was partially offset by increases from commercial and residential customer growth, added loads under higher commercial rate schedules, and added rate-base returns on certain investments.

Industrial Sales and Transportation

Industrial customers have the option of purchasing sales or transportation services from the utility. Under the sales service, the customer buys the gas commodity from the utility. Under the transportation service, the customer buys the gas commodity directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's

Table of Contents

decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service options, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special charges for changes between elections, and in some cases, meeting a minimum or maximum volume requirement before changing options.

Industrial sales and transportation highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,		QTR Change	YTD Change
In thousands	2015	2014	2015	2014		
Volumes (therms):						
Industrial - firm sales	7,352	7,469	23,308	25,034	(117)	(1,726)
Industrial - firm transportation	29,149	32,067	104,773	111,893	(2,918)	(7,120)
Industrial - interruptible sales	14,739	15,146	51,984	56,829	(407)	(4,845)
Industrial - interruptible transportation	49,762	47,804	154,917	152,511	1,958	2,406
Total volumes	101,002	102,486	334,982	346,267	(1,484)	(11,285)
Utility margin:						
Industrial - firm and interruptible sales	$3,259	$3,179	$9,641	$9,775	$80	$(134)
Industrial - firm and interruptible transportation	3,974	3,783	12,424	12,378	191	46
Total utility margin	$7,233	$6,962	$22,065	$22,153	$271	$(88)

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Industrial sales and transportation volumes decreased 1.5 million therms, while industrial margins increased by $0.3 million or 4%. The volume decrease was primarily due to lower demand from a few large customers, while the margin increase was largely due to an increase in industrial customers under higher margin rate schedules.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Industrial sales and transportation volumes decreased 11.3 million therms primarily due to lower usage from warmer weather and lower demand from a few large volume transportation customers on lower margin rate schedules. Margin decreased $0.1 million due to higher fee revenues in the prior year from increased usage from the cold weather event in February 2014, partially offset by an increase in industrial customers under higher margin rate schedules.

Cost of Gas

Cost of gas as reported by the utility includes gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, gas reserves costs, 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 expect to earn a profit or incur a loss on the gas commodity purchased for customers; however, in Oregon we have an incentive sharing mechanism which has been described under “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above. In addition to the PGA incentive sharing mechanism, gains and losses from hedge contracts entered into after annual PGA rates are effective for Oregon customers are also required to be shared and therefore may impact net income. Further, we also have a regulatory agreement whereby we earn a rate of return on our investment in the gas reserves acquired under the original agreement with Encana and include gas from our amended gas reserves agreement at a fixed rate of $0.4725 per therm, which are also reflected in utility margin. 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 our 2014 Form 10-K for additional information, as well as Note 12 in this report.

Table of Contents

Cost of gas highlights include:

In thousands, except as noted	Three Months Ended September 30,		Nine Months Ended September 30,		QTR Change	YTD Change
	2015	2014	2015	2014		
Cost of gas	$35,856	$32,227	$223,737	$245,708	$3,629	$(21,971)
Volumes sold (therms)(1)	73,028	69,503	423,521	491,214	3,525	(67,693)
Average cost of gas (cents per therm)(1)	$0.49	$0.46	$0.53	$0.50	$0.03	0.03
Gain (loss) from gas cost incentive sharing	431	(84)	1,992	(2,345)	515	4,337

(1) This calculation excludes volumes delivered to transportation only customers.

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Cost of gas increased $3.6 million or 11% primarily due to a 7% increase in average cost of gas.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Cost of gas decreased $22.0 million or 9% primarily due to a 14% decrease in sales volume due to warmer weather, partially offset by a 6% increase average cost of gas.

Due to the extreme cold weather event in February 2014, we experienced a record sendout and consequently, the higher volumes of gas purchased at higher gas prices at that time resulted in a margin loss in 2014 compared to a margin gain thus far in 2015 as prices were lower due to the record warmer weather. For a discussion of our gas cost incentive sharing mechanism, see “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our 75% ownership interest in the Gill Ranch underground storage facility in California. We also contract with an independent energy marketing company to provide asset management services using utility and non-utility storage and transportation capacity, the results of which are included in this segment.

Gas storage segment highlights include:

In thousands, except per share data	Three Months Ended September 30,		Nine Months Ended September 30,		QTR Change	YTD Change
	2015	2014	2015	2014		
Gas storage net income	$799	$2	$827	$472	$797	$355
EPS - gas storage segment	0.04	—	0.04	0.02	0.04	0.02
Operating revenues	5,596	4,782	16,232	17,655	814	(1,423)
Operating expenses	3,392	3,856	12,234	13,661	(464)	(1,427)

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Gas storage net income increased $0.8 million due to a $0.8 million increase in operating revenues from slightly higher contract prices for the 2015-16 gas storage year and a $0.5 million decrease in operating expenses due to lower compensation expenses and property taxes at our Gill Ranch facility.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Gas storage net income increased $0.4 million due to a $1.4 million decrease in operating expenses from lower repair and power costs at our

Gill Ranch facility and a $0.9 million decrease in interest expense related to the retirement of $20 million of Gill Ranch's debt in June of 2014. These decreases were offset by a $1.4 million reduction in operating revenues mainly due to lower contract prices for the 2014-15 gas storage year. Over the past few years, market prices for natural gas storage, particularly in California, were negatively affected by the abundant supply of natural gas, low volatility of natural gas prices, and surplus gas storage capacity. We contracted capacity for the 2014-15 gas storage year with shorter-term contracts at lower market prices than in previous years, which contributed to the decline in gas storage operating revenues.

Table of Contents

Our gas storage segment financial results have been negatively impacted by the decline in market conditions, particularly at our Gill Ranch facility. Our Mist facility benefits from a more constrained regional supply system in the Pacific Northwest region and is impacted to a lesser extent from market fluctuations. Despite current market conditions, we continue to believe in the long-term need for gas storage in California and anticipate improvement in gas storage values driven by California's renewable portfolio standards and carbon reduction targets.

Prices for the 2015-16 gas year showed improvement, however remained low relative to the pricing in our original long-term contracts. In the future, we may see an improvement in gas storage values and an increase in the demand for natural gas driven by a number of factors, including changes in electric generation triggered by California's renewable portfolio standards, an increase in use of alternative fuels to meet carbon reduction targets, recovery of the California economy, growth of domestic industrial manufacturing, potential exports of liquefied natural gas from the west coast, and other favorable market conditions in and around California. These factors, if they occur, may contribute to higher summer/winter natural gas price spreads, gas price volatility, and gas storage values. We are continuing to explore opportunities to increase revenues through enhanced services for storage customers and capitalizing on opportunities that fit our business-risk profile. Refer to Note 2 in our 2014 Form 10-K for more information regarding our accounting for impairment of long-lived assets.

Other

Other business activities primarily consist of NNG Financial's equity investment in KB Pipeline, an equity investment in TWH, and other miscellaneous non-utility investments. Contributions from our other businesses produced less than $0.1 million of net income for the three months ended September 30, 2015 and 2014. For the nine months ended September 30, 2015 our other businesses produced just over $0.1 million compared to $0.3 million for the same period in 2014. See Note 4 and Note 11 for further details on our other activities and our investment in TWH.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In thousands	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	QTR Change	YTD Change
Operations and maintenance	$32,031	$32,968	$121,458	$103,085	$(937)	$18,373

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Operations and maintenance expense decreased $0.9 million due to the following:

- a $1.2 million decrease in utility non-payroll expense, primarily due to lower contract work costs; offset by
- a $0.3 million increase in benefit expense including increased employee incentive and pension costs.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Operations and maintenance expense increased $18.4 million due to the following:

- the $15 million pre-tax charge, or $9.1 million after-tax, for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals. We also expensed an additional $1 million related to the Order; and
- a $4.3 million increase in compensation and benefit expense including increased employee incentive, pension, and health care costs, as well as higher wage rates under the new union labor contract, which became effective June 1, 2014; offset by
- a $1.9 million decrease primarily related to 2014 repair and power costs at our Gill Ranch gas storage facility.

Delinquent customer receivable balances and bad debt expense continue to remain at historically low levels. The utility's annualized bad debt expense as a percentage of revenues was 0.1% for the nine months ended September 30, 2015 and has remained well below 0.5% of revenues every year since 2007.

Table of Contents

Other Income and Expense, Net

Other income and expense, net highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,		QTR Change	YTD Change
In thousands	2015	2014	2015	2014		
Other income and expense, net	$746	$407	$6,930	$2,052	$339	$4,878

THREE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Other income increased $0.3 million primarily due to a decrease in regulatory interest expense from the application of insurance proceeds under the SRRM, partially offset by a decrease in interest income from environmental assets accruing interest at a lower rate under the SRRM.

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Other income increased $4.9 million due to the recognition of a net $5.3 million related to the equity earnings included in interest income from our deferred environmental expenses. We realized the equity earnings on these deferred regulatory asset balances as a result of the OPUC SRRM Order we received in February 2015. Offsetting the $5.3 million was a $0.4 million decrease in interest income primarily from environmental assets accruing interest at a lower rate under the SRRM offset in part by a decrease in regulatory interest expense from the application of insurance proceeds under the SRRM.

Interest Expense

Interest expense highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,		QTR Change	YTD Change
In thousands	2015	2014	2015	2014		
Interest expense	$10,111	$10,805	$31,030	$34,024	$(694)	$(2,994)

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Interest expense decreased $0.7 million for the quarter and $3.0 million for the nine month period due to the redemption of $40 million of utility FMBs in June 2015, $60 million of utility FMBs in 2014, and the retirement of $20 million of Gill Ranch's debt in June 2014.

Income Tax Expense

Income tax expense highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,		QTR	YTD
In thousands	2015	2014	2015	2014	Change	Change
Income tax expense	$(4,553)	$(6,742)	$15,944	$21,023	$2,189	$(5,079)

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Increases or decreases in income tax expense are correlated with changes in pre-tax income. Additionally, there was a $0.6 million income tax charge in the first quarter of 2014 due to the revaluation of deferred tax balances related to a higher effective tax rate in Oregon.

FINANCIAL CONDITION

Capital Structure
One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45% to 50% common stock equity and 50% to 55% long-term and short-term debt, and with a target utility capital structure of 50% common stock and 50% long-term debt. When additional capital is required, debt or equity securities are issued depending on both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See “Liquidity and Capital Resources” below and Note 6.

Achieving both the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and provide access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	September 30,				December 31,	
	2015		2014		2014	
Common stock equity	47.3	%	46.9	%	46.1	%
Long-term debt	38.7		38.8		37.4	
Short-term debt, including any current maturities of long-term debt	14.0		14.3		16.5	
Total	100.0	%	100.0	%	100.0	%

Liquidity and Capital Resources
At September 30, 2015, we had $5.2 million of cash and cash equivalents compared to $8.3 million at September 30, 2014. We also had $4.5 million and $3.0 million in restricted cash at Gill Ranch at September 30, 2015 and 2014, respectively, which is 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 and add short-term borrowing capacity. In addition, we may also pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC. Our use of retained earnings is not subject to those restrictions.

Utility Segment
For the utility segment, the short-term borrowing requirements typically peak during colder winter months when the utility borrows money to cover the lag between natural gas purchases and bill collections from customers. Our short-term liquidity for the utility is primarily provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, as well as available cash from multi-year credit facilities, company-owned life insurance policies, and the sale of long-term debt. Utility long-term debt proceeds are primarily used to finance utility capital expenditures, refinance maturing debt of the utility, and provide temporary funding for other general corporate purposes of the utility.

Based on our current debt ratings (see "Credit Ratings" below), we have been able to issue commercial paper and long-term debt at attractive rates and have not needed to borrow or issue letters of credit from our back-up credit facility. In the event we are not able to issue new debt due to adverse market conditions or other reasons, we expect our near term liquidity needs can be met using internal cash flows or, for the utility segment, drawing upon our committed credit facility. We also have a universal shelf registration statement 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, 2015, we have Board authorization to issue up to $325 million of additional FMB's. We also have OPUC approval to issue up to $325 million of additional long-term debt for approved purposes.

In the event 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 another form of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings while we were in a net loss position. We were not near the threshold for posting collateral at September 30, 2015. However, if the credit risk-related contingent features underlying these contracts were triggered on September 30, 2015, assuming our long-term debt ratings dropped to non-investment

37

grade levels, we could have been required to post $22.1 million of collateral to our counterparties. See "Credit Ratings" below and Note 12.

Other items that may have a significant impact on our liquidity and capital resources include pension contribution requirements, expiration of bonus tax depreciation, environmental expenditures and insurance recoveries. See "Cash Flows—Operating Activities" below.

With respect to pensions, we expect to make significant contributions to our company-sponsored defined benefit plan, which is closed to new employees, over the next several years until we are fully funded under the Pension Protection Act rules, including the new rules issued under the Moving Ahead for Progress in the 21st Century Act (MAP-21) and the Highway and Transportation Funding Act of 2014 (HATFA). See "Cash Flows—Operating Activities" below for expected contribution amounts.

Gas Storage Segment

Short-term liquidity for the gas storage segment is supported by cash balances, internal cash flow from operations, external financing, and funds from its parent company. The abundant supply of natural gas, low volatility of natural gas prices, and available gas storage capacity, particularly in California, have recently resulted in lower storage market prices than we have seen in previous years. The amount and timing of our Gill Ranch facility's cash flows from year to year are uncertain, as the majority of these storage contracts are currently short-term. We have seen slightly higher contract prices for the 2015-16 storage year, but overall prices are still significantly lower than the long-term contracts that expired at the end of the 2013-14 storage year. As such, we expect continuing challenges for Gill Ranch in 2015 causing negative cash flows from operations in 2015. We do not anticipate material changes in our ability to access sources of cash for short-term liquidity.

In November 2011, Gill Ranch issued $40 million of senior collateralized debt, with a fixed interest rate of 7.75% on $20 million and a variable interest rate on the remaining $20 million, with a maturity date of November 30, 2016. Under the debt agreement, Gill Ranch was subject to certain covenants and restrictions. We have amended this agreement twice, which resulted in repayment of the $20 million variable-rate outstanding debt during the second quarter of 2014, suspension of the EBITDA covenant requirement through the maturity date, and maintenance of a debt reserve account, which was fixed at $4.5 million as of June 30, 2015, and is required to increase by $1.5 million on each of January 30, 2016 and August 30, 2016. In addition, under the amended agreement, Gill Ranch was required to receive common equity contributions from its parent NWN Gas Storage of at least $2 million by August 31, 2015 and complied with this requirement. Additionally, Gill Ranch is required to receive equity contributions from its parent of at least $4 million by August 31, 2016. The senior collateralized debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to us and other entities in the consolidated group.

Consolidated

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

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities. See “Credit Agreements” below. At

September 30, 2015 and 2014, our utility had commercial paper outstanding of $225.2 million and $190.0 million, respectively. The effective interest rate on the utility's commercial paper outstanding at September 30, 2015 and 2014 was 0.4% and 0.3%, respectively.

Table of Contents

Credit Agreements

We have a $300 million revolving credit facility, with a feature that allows us to request increases in the total commitment amount, up to a maximum of $450 million. The final maturity date of the agreement is in December 2019.

All lenders under the agreement are major financial institutions with committed balances and investment grade credit ratings as of September 30, 2015 as follows:

Lender rating, by category, in millions	Loan Commitment
AA/Aa	$234
A/A1	66
BBB/Baa	—
Total	$300

Based on credit market conditions, it is possible one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency; however, we do not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings.

Our credit agreement permits the issuance of letters of credit in an aggregate amount of up to $100 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreements is due and payable on or before the maturity date. There were no outstanding balances under this credit agreement at September 30, 2015 or 2014. The credit agreement requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at September 30, 2015 and 2014, with consolidated indebtedness to total capitalization ratios of 52.7% and 53.1%, respectively.

The agreement also requires us to maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody’s) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings by S&P or Moody’s is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreements when ratings are changed. See “Credit Ratings” below.

Credit Ratings

Our credit ratings are a factor of our liquidity, potentially affecting our access to capital markets including the commercial paper market. Our credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. There were no changes in our credit ratings during the quarter. 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-2
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	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 or reference to 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.

Table of Contents

Maturity and Redemption of Long-Term Debt

We redeemed $40 million of FMB's with a coupon rate of 4.70% in June 2015. There are no scheduled redemptions in the coming twelve months.

See Part II, Item 7, "Financial Condition—Contractual Obligations" in our 2014 Form 10-K for long-term debt maturing over the next five years.

Cash Flows

Operating Activities

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

Operating activity highlights include:

	Nine Months Ended September 30,		
In thousands	2015	2014	Change
Cash provided by operating activities	$172,745	$214,864	$(42,119)

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Cash provided by operating activities decreased $42.1 million due to the following:

- a decrease of $97.6 million in deferred environmental recoveries reflecting insurance settlements totaling approximately $102 million received in the first nine months of 2014, which did not recur in 2015;
- a $15.0 million non-cash regulatory disallowance of prior environmental cost deferrals in 2015;
- an increase of $49.2 million from changes in deferred gas costs, net due to lower actual gas prices than prices embedded in the PGA compared to the prior year; and
- a net decrease of $3.0 million from changes in working capital related to receivables, inventories and accounts payable due to warmer weather in the first nine months of 2015 compared to 2014.

The non-cash pension expense recognized on the income statement for the nine months ended September 30, 2015 was $4.2 million, compared to $3.8 million for the same period in 2014. Changes in pension expense are mitigated by our balancing account in Oregon; and therefore, net non-cash pension expenses are expected to remain relatively flat in the coming years.

During the nine months ended September 30, 2015, we contributed $11.8 million to our utility's qualified defined benefit pension plan, compared to $10.5 million for the same period in 2014. We plan to make $2.3 million in contributions during the remainder of 2015. The amount and timing of future contributions will depend, to a certain extent, on market interest rates, investment returns on the plan's assets, and future federal funding requirements.

Bonus tax depreciation of 50 percent has been available in recent years, resulting in net operating loss (NOL) carryforwards that are available to reduce current year taxable income. Bonus tax depreciation expired at the end of 2014 and has not yet been enacted for 2015. We anticipate taxable income for 2015 will be in excess of the available NOL carryforwards, and as of September 30, 2015, an income tax prepaid balance of $8.8 million has been recorded.

The final tangible property regulations applicable to all taxpayers were issued on September 13, 2013 and are generally effective for taxable years beginning on or after January 1, 2014. In addition, procedural guidance related to the regulations was issued under which taxpayers may make accounting method changes to comply with the regulations. We have evaluated the regulations and do not anticipate any material impact. However, unit-of-property guidance applicable to natural gas distribution networks has not yet been issued and is expected by the end of 2015. We will further evaluate the effect of these regulations after this guidance is issued, but believe our current method is materially consistent with the new regulations and do not expect these regulations to have a material effect on our financial statements.

Table of Contents

Investing Activities

Investing activity highlights include:

	Nine Months Ended September 30,		
In thousands	2015	2014	Change
Total cash used in investing activities	$(88,242)	$(107,204)	$18,962
Capital expenditures	(86,923)	(86,552)	(371)
Utility gas reserves	(1,165)	(21,734)	20,569

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Cash used in investing activities decreased $19.0 million due to lower investments in utility gas reserves, partially offset by higher capital expenditures at the utility.

Under the amended gas reserves agreement, we ended our original drilling program with Encana, but increased our assigned working interests in certain sections of the Jonah field. We continue to evaluate and make decisions whether or not to participate with Jonah Energy in additional wells drilled, and currently we do not expect to drill any additional wells in 2015. See Note 10 for additional information regarding the amended gas reserve agreement.

We received acknowledgment of our recently filed Integrated Resource Plan (IRP), which outlines long-term capital investments based on projected customer and infrastructure needs. Among other things, the IRP included projected infrastructure projects such as continued refurbishments of the Newport Liquefied Natural Gas (LNG) facility in Oregon over the next three years with an expected investment of ranging from $20 to $25 million, and upgrading distribution infrastructure in Clark County, Washington, which could total approximately $25 million over the next five years. In addition, the IRP also included recall of non-utility Mist gas storage capacity of 0.3 million therms per day of deliverability and 0.7 Bcf of associated storage capacity to serve core utility customer needs, which occurred on May 1, 2015. Finally, the IRP discusses various changes to the resource portfolio and preserves the optionality of participating in both the Trail West and Pacific Connector interstate connector pipeline projects. These and other investments are included in our expected capital expenditures in Part II, Item 7, "Financial Condition—Cash Flows—Investing Activities” in the 2014 Form 10-K.

The utility plans to expand its North Mist facility, supported by a contract with PGE to serve their gas-fired electric power generation facilities at Port Westward, which is located approximately 15 miles from Mist. In early 2015, the utility received authorization from PGE to begin permitting and land acquisition work. The estimated cost of the expansion is approximately $125 million with a potential in-service date in 2018 or 2019. This project is subject to PGE's final approval of estimated projected costs and a notice to proceed, as well as the utility's receipt of permits and certain land rights needed for the project.

Financing Activities

Financing activity highlights include:

	Nine Months Ended September 30,		
In thousands	2015	2014	Change
Total cash used in financing activities	$(88,810)	$(108,856)	$20,046
Change in short-term debt	(9,500)	1,800	(11,300)
Long-term debt retired	(40,000)	(80,000)	40,000

NINE MONTHS ENDED SEPTEMBER 30, 2015 COMPARED TO SEPTEMBER 30, 2014. Cash used in financing activities decreased $20.0 million due to the receipt of approximately $91 million of proceeds from our insurance settlements, which was used to reduce our short-term debt balance in the same period of 2014. In addition, we retired $40 million of utility FMBs during the first nine months of 2015 compared to $80 million retired for the same period of 2014.

Table of Contents

Ratios of Earnings to Fixed Charges

For the nine and twelve months ended September 30, 2015 and the twelve months ended December 31, 2014, our ratios of earnings to fixed charges computed using the method set forth in Item 503(d) of the SEC's Regulation S-K, were 2.22, 3.02, and 3.13, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, with fixed charges consisting of interest on all indebtedness, the amortization of debt discount or premium and expense, and the estimated interest portion of rentals charged to income. See Exhibit 12 for the detailed ratio calculation.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. See Part II, Item 7, “Application of Critical Accounting Policies and Estimates” in our 2014 Form 10-K. At September 30, 2015, we had a net regulatory asset of $49.8 million for deferred environmental costs, which includes deferred payments and interest of $60.6 million and $88.9 million for additional costs expected to be paid in the future, partially offset by $99.7 million of insurance recoveries. If it is determined that 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 see also "Regulatory Matters—Rate Mechanisms—Environmental Costs".

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements using 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.

See Note 2 for a discussion of the $15 million regulatory disallowance related to the SRRM Order received in February 2015. There have been no material changes to the information provided in the 2014 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 2014 Form 10-K).

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

Table of Contents

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 ended September 30, 2015. See Part II, Item 1A, “Risk Factors” in this report and Part II, Item 7A, “Quantitative and Qualitative Disclosures about Market Risk” in the 2014 Form 10-K for details regarding these risks.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, 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 (SEC) 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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in 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, 2015 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).

Table of Contents

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 2014 Form 10-K, we have only routine nonmaterial litigation that occurs in the ordinary course of our business.

ITEM 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, Item 1A, "Risk Factors" in our 2014 Form 10-K. In addition to the other information set forth in this report, you should carefully consider those risk factors, which could materially affect our business, financial condition or results of operations.

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

The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended September 30, 2015:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [2]
Balance forward			2,124,528	$ 16,732,648
07/01/15 - 07/31/15	1,405	$43.82	—	—
08/01/15 - 08/31/15	22,799	45.11	—	—
09/01/15 - 09/30/15	3,487	43.45	—	—
Total	27,691	$44.84	2,124,528	$ 16,732,648

(1) During the quarter ended September 30, 2015, 24,298 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 3,393 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, 2015, 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, 2016 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, 2015, 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.

44

Table of Contents

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 3, 2015

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

Table of Contents

NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Quarterly Report on Form 10-Q
For the Quarter Ended September 30, 2015

Exhibit Number	Document
10a	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated effective as of September 24, 2015.
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's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, 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.