NORTHWEST NATURAL GAS CO
Form 10-Q
August 04, 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 June 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 [ ] Smaller Reporting Company [ ]

(Do not check if a Smaller Reporting Company)

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

At July 24, 2015, 27,362,842 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended June 30, 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” 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)

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2015	2014	2015	2014
Operating revenues	$138,280	$133,169	$399,945	$426,555
Operating expenses:				
Cost of gas	62,176	58,280	187,881	213,481
Operations and maintenance	35,311	34,731	89,427	70,117
General taxes	7,649	7,183	16,381	15,365
Depreciation and amortization	20,230	19,709	40,341	39,298
Total operating expenses	125,366	119,903	334,030	338,261
Income from operations	12,914	13,266	65,915	88,294
Other income and expense, net	1,135	262	6,184	1,645
Interest expense, net	10,438	11,677	20,919	23,219
Income before income taxes	3,611	1,851	51,180	66,720
Income tax expense	1,414	780	20,497	27,765
Net income	2,197	1,071	30,683	38,955
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $217 and $108 for the three months ended and $433 and $216 for the six months ended June 30, 2015 and 2014, respectively	331	166	663	331
Comprehensive income	$2,528	$1,237	$31,346	$39,286
Average common shares outstanding:				
Basic	27,343	27,139	27,322	27,116
Diluted	27,388	27,182	27,378	27,158
Earnings per share of common stock:				
Basic	$0.08	$0.04	$1.12	$1.44
Diluted	0.08	0.04	1.12	1.43
Dividends declared per share of common stock	0.465	0.460	0.930	0.920

See Notes to Unaudited Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2015	June 30, 2014	December 31, 2014
Assets:			
Current assets:			
Cash and cash equivalents	$4,466	$17,240	$9,534
Accounts receivable	32,041	38,621	69,818
Accrued unbilled revenue	12,760	14,592	57,963
Allowance for uncollectible accounts	(723)	(1,404)	(969)
Regulatory assets	63,016	38,265	68,562
Derivative instruments	1,023	11,191	243
Inventories	76,511	60,808	77,832
Gas reserves	18,214	20,373	20,020
Income taxes receivable	—	—	1,000
Deferred tax assets	12,693	4,915	23,785
Other current assets	15,348	14,518	34,772
Total current assets	235,349	219,119	362,560
Non-current assets:			
Property, plant, and equipment	3,042,671	2,965,226	2,992,560
Less: Accumulated depreciation	893,722	879,296	870,967
Total property, plant, and equipment, net	2,148,949	2,085,930	2,121,593
Gas reserves	121,355	130,280	129,280
Regulatory assets	342,806	267,248	368,908
Derivative instruments	1,369	1,202	—
Other investments	68,147	67,689	68,238
Restricted cash	4,500	3,000	3,000
Other non-current assets	9,404	12,646	11,366
Total non-current assets	2,696,530	2,567,995	2,702,385
Total assets	$2,931,879	$2,787,114	$3,064,945

See Notes to Unaudited Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2015	June 30, 2014	December 31, 2014
Liabilities and equity:			
Current liabilities:			
Short-term debt	$190,300	$74,200	$234,700
Current maturities of long-term debt	—	100,000	40,000
Accounts payable	49,505	68,973	91,366
Taxes accrued	8,782	15,769	10,031
Interest accrued	5,922	7,053	6,079
Regulatory liabilities	26,712	26,742	19,105
Derivative instruments	15,017	1,490	29,894
Other current liabilities	31,332	34,507	38,235
Total current liabilities	327,570	328,734	469,410
Long-term debt	621,700	621,700	621,700
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	524,099	489,892	530,965
Regulatory liabilities	328,646	309,327	317,205
Pension and other postretirement benefit liabilities	233,554	145,861	236,735
Derivative instruments	1,077	191	3,515
Other non-current liabilities	118,269	120,423	118,094
Total deferred credits and other non-current liabilities	1,205,645	1,065,694	1,206,514
Commitments and contingencies (see Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,363, 27,147, and 27,284 at June 30, 2015 and 2014 and December 31, 2014, respectively	378,887	369,315	375,117
Retained earnings	407,490	407,698	402,280
Accumulated other comprehensive loss	(9,413)	(6,027)	(10,076)
Total equity	776,964	770,986	767,321
Total liabilities and equity	$2,931,879	$2,787,114	$3,064,945

See Notes to Unaudited Consolidated Financial Statements

4

Table of Contents

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

In thousands	Six Months Ended June 30, 2015	2014
Operating activities:		
Net income	$30,683	$38,955
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	40,341	39,298
Regulatory amortization of gas reserves	10,023	8,680
Deferred tax liabilities, net	6,886	989
Non-cash expenses related to qualified defined benefit pension plans	3,032	2,540
Contributions to qualified defined benefit pension plans	(5,810)	(6,000)
Deferred environmental (expenditures), net of recoveries	(5,659)	92,104
Non-cash regulatory disallowance of prior environmental cost deferrals	15,000	—
Non-cash interest income on deferred environmental expenses	(5,322)	—
Other	418	1,010
Changes in assets and liabilities:		
Receivables	85,121	89,951
Inventories	1,321	(139)
Taxes accrued	(249)	8,447
Accounts payable	(37,532)	(24,472)
Interest accrued	(157)	(50)
Deferred gas costs	21,718	(18,812)
Other, net	7,670	744
Cash provided by operating activities	167,484	233,245
Investing activities:		
Capital expenditures	(58,072)	(52,489)
Utility gas reserves	(1,945)	(18,632)
Restricted cash	(1,500)	1,000
Other	201	(1,043)
Cash used in investing activities	(61,316)	(71,164)
Financing activities:		
Common stock issued, net	812	3,733
Long-term debt retired	(40,000)	(20,000)
Change in short-term debt	(44,400)	(114,000)
Cash dividend payments on common stock	(25,398)	(24,938)
Other	(2,250)	893
Cash used in financing activities	(111,236)	(154,312)
(Decrease) increase in cash and cash equivalents	(5,068)	7,769
Cash and cash equivalents, beginning of period	9,534	9,471
Cash and cash equivalents, end of period	$4,466	$17,240
Supplemental disclosure of cash flow information:		
Interest paid	$19,615	$23,270
Income taxes paid (net of refunds)	4,625	14,945

See Notes to Unaudited Consolidated Financial Statements

5

Table of Contents

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

Our 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 six months ended June 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		
	June 30,		December 31,
In thousands	2015	2014	2014
Current:			
Unrealized loss on derivatives(1)	$15,017	$1,466	$29,889
Gas costs	19,070	19,268	21,794
Other(2)	28,929	17,531	16,879
Total current	$63,016	$38,265	$68,562
Non-current:			
Unrealized loss on derivatives(1)	$1,077	$191	$3,515
Pension balancing(3)	38,255	28,997	32,541
Income taxes	44,767	49,007	47,427
Pension and other postretirement benefit liabilities	193,356	120,942	201,845
Environmental costs(4)	49,917	52,117	58,859
Gas costs	2,472	3,768	5,971
Other(2)	12,962	12,226	18,750
Total non-current	$342,806	$267,248	$368,908

	Regulatory Liabilities		
	June 30,		December 31,
In thousands	2015	2014	2014
Current:			
Gas costs	$20,087	$6,423	$5,700
Unrealized gain on derivatives(1)	1,015	11,286	240
Other(2)	5,610	9,033	13,165
Total current	$26,712	$26,742	$19,105
Non-current:			
Gas costs	$3,615	$1,057	$2,507
Unrealized gain on derivatives(1)	1,369	1,202	—
Accrued asset removal costs(5)	320,206	303,567	311,238
Other(2)	3,456	3,501	3,460
Total non-current	$328,646	$309,327	$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) 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.

(3) The deferral of certain pension expenses above or below the amount set in rates was approved by the Public Utility Commission of Oregon (OPUC), with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower net periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of interest income recognized when amounts are collected in rates.

(4) Environmental costs relate to specific sites approved for regulatory deferral by the 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. See Note 13.

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

7

Table of Contents

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 factors the OPUC deemed relevant. The Company 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 component 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.

FAIR VALUE MEASUREMENT. On May 1, 2015, the FASB issued ASU 2017-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). The amendment 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. NW Natural does not expect the ASU to affect its financial statements and does not expect it to materially affect its 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. This amendment provides customers guidance on how to determine whether a cloud computing arrangement includes a software license. The new requirements are effective for the Company January 1, 2016. The amendment can be applied prospectively or retrospectively and early adoption is permitted. NW Natural does not expect the ASU to materially affect its 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. NW Natural does not expect the ASU to materially affect its 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 obligation is satisfied. The new requirements prescribe either a full retrospective or simplified transition adoption method. On July 9, 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 December 15, 2016. The Company is currently assessing the effect of this standard on our financial statements and disclosures.

Table of Contents

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. Diluted earnings per share are calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2015	2014	2015	2014
Net income	$2,197	$1,071	$30,683	$38,955
Average common shares outstanding - basic	27,343	27,139	27,322	27,116
Additional shares for stock-based compensation plans outstanding	45	43	56	42
Average common shares outstanding - diluted	27,388	27,182	27,378	27,158
Earnings per share of common stock - basic	$0.08	$0.04	$1.12	$1.44
Earnings per share of common stock - diluted	$0.08	$0.04	$1.12	$1.43
Additional information:				
Antidilutive shares excluded from net income per diluted common share calculation	35	39	27	28

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 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 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 our 2014 Form 10-K for further discussion of our segments.

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

	Three Months Ended June 30,			
In thousands	Utility	Gas Storage	Other	Total
2015				
Operating revenues	$132,891	$5,333	$56	$138,280
Depreciation and amortization	18,602	1,628	—	20,230
Income from operations	12,163	739	12	12,914
Net income (loss)	2,245	(86)	38	2,197
Capital expenditures	30,464	473	—	30,937
2014				
Operating revenues	$128,075	$5,038	$56	$133,169
Depreciation and amortization	18,087	1,622	—	19,709
Income (loss) from operations	13,735	(485)	16	13,266

Net income (loss)	2,205	(1,157)	23	1,071
Capital expenditures	26,726	175	—	26,901

9

Table of Contents

	Six Months Ended June 30,			
In thousands	Utility	Gas Storage	Other	Total
2015				
Operating revenues	$389,197	$10,636	$112	$399,945
Depreciation and amortization	37,077	3,264	—	40,341
Income from operations	64,043	1,794	78	65,915
Net income	30,580	28	75	30,683
Capital expenditures	56,273	1,799	—	58,072
Total assets at June 30, 2015	2,646,457	270,509	14,913	2,931,879
2014				
Operating revenues	$413,570	$12,873	$112	$426,555
Depreciation and amortization	36,054	3,244	—	39,298
Income from operations	85,192	3,068	34	88,294
Net income	38,224	470	261	38,955
Capital expenditures	52,076	413	—	52,489
Total assets at June 30, 2014	2,487,771	282,939	16,404	2,787,114
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.

The following table presents additional segment information concerning utility margin:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2015	2014	2015	2014
Utility margin calculation:				
Utility operating revenues	$132,891	$128,075	$389,197	$413,570
Less: Utility cost of gas	62,176	58,280	187,881	213,481
Utility margin	$70,715	$69,795	$201,316	$200,089

Table of Contents

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 first six months of 2015, 49,939 performance-based shares were granted under the LTIP based on target-level awards with a weighted-average grant date fair value of $51.76 per share. As of June 30, 2015, there was $2.7 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 first six months of 2015, 38,490 RSUs were granted under the LTIP with a weighted-average grant date fair value of $46.16 per share. The fair value of a RSU is equal to the closing market price of the Company's common stock on the grant date. As of June 30, 2015, there was $3.4 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 include a performance-based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU.

6. DEBT

Short-Term Debt

At June 30, 2015, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 111 days, an average maturity of 51 days, and an outstanding balance of $190.3 million. The carrying cost of our commercial paper approximates fair value using Level 2 inputs due to the short-term nature of the notes. See Note 2 in our 2014 Form 10-K for a description of the fair value hierarchy.

Long-Term Debt

At June 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.

At June 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

Table of Contents

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 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 our 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:

	June 30,		December 31,
In thousands	2015	2014	2014
Carrying amount	$621,700	$721,700	$661,700
Estimated fair value	695,902	807,617	756,808

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

12

Table of Contents

7. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

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

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2015	2014	2015	2014
Service cost	$2,309	$1,918	$145	$136
Interest cost	4,595	4,512	292	309
Expected return on plan assets	(5,174)	(4,886)	—	—
Amortization of net actuarial loss	4,561	2,580	125	46
Amortization of prior service costs	58	56	49	49
Net periodic benefit cost	6,349	4,180	611	540
Amount allocated to construction	(1,879)	(1,201)	(198)	(171)
Amount deferred to regulatory balancing account[(1)]	(2,165)	(1,123)	—	—
Net amount charged to expense	$2,305	$1,856	$413	$369

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2015	2014	2015	2014
Service cost	$4,618	$3,836	$290	$271
Interest cost	9,190	9,024	583	619
Expected return on plan assets	(10,348)	(9,772)	—	—
Amortization of net actuarial loss	9,122	5,160	251	92
Amortization of prior service costs	116	112	98	98
Net periodic benefit cost	12,698	8,360	1,222	1,080
Amount allocated to construction	(3,704)	(2,402)	(389)	(341)
Amount deferred to regulatory balancing account[(1)]	(4,340)	(2,224)	—	—
Net amount charged to expense	$4,654	$3,734	$833	$739

(1) 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 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 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 June 30,		Six Months Ended June 30,	
In thousands	2015	2014	2015	2014
Beginning balance	$(9,744)	$(6,193)	$(10,076)	$(6,358)
Amounts reclassified from AOCL:				
Amortization of prior service costs	—	(2)	—	(4)
Amortization of actuarial losses	548	276	1,096	551
Total reclassifications before tax	548	274	1,096	547
Tax expense	(217)	(108)	(433)	(216)
Total reclassifications for the period	331	166	663	331

Ending balance	$(9,413)	$(6,027)	$(9,413)	$(6,027)

13

Table of Contents

Employer Contributions to Company-Sponsored Defined Benefit Pension Plan
For the six months ended June 30, 2015, we made cash contributions totaling $5.8 million to our qualified defined benefit pension plan. We expect further plan contributions of $9.2 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). Company contributions to this plan totaled $2.0 million and $1.9 million for the six months ended June 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.

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 June 30,		Six Months Ended June 30,	
Dollars in thousands	2015	2014	2015	2014
Income tax at statutory rates (federal and state)	$1,429	$728	$20,321	$26,449
Increase (decrease):				
Differences required to be flowed-through by regulatory commissions	85	61	1,414	1,494
Other, net	(100)	(9)	(1,238)	(178)
Income tax expense	$1,414	$780	$20,497	$27,765
Effective income tax rate	39.2%	42.1%	40.0%	41.6%

Increases or decreases in income tax expense are correlated with changes in pre-tax income. The effective tax rate for the three and six months ended June 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.

The Company's 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:

In thousands	June 30, 2015	2014	December 31, 2014
Utility plant in service	$2,701,010	$2,624,774	$2,661,097
Utility construction work in progress	38,024	36,798	24,886
Less: Accumulated depreciation	857,373	847,828	836,510
Utility plant, net	1,881,661	1,813,744	1,849,473
Non-utility plant in service	296,046	297,269	297,295
Non-utility construction work in progress	7,591	6,385	9,282
Less: Accumulated depreciation	36,349	31,468	34,457
Non-utility plant, net	267,288	272,186	272,120
Total property, plant, and equipment	$2,148,949	$2,085,930	$2,121,593
Capital expenditures in accrued liabilities	$6,081	$9,826	$8,757

10. GAS RESERVES

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

We entered into our original agreements with Encana Oil & Gas (USA) Inc. (Encana) in 2011 to develop physical gas reserves to provide long-term gas price protection for utility customers. Encana began drilling in 2011 under these agreements. 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 and provides long-term price protection for our utility customers.

On March 28, 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 LLC (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.

We were notified by Jonah Energy of investment opportunities in the sections of the Jonah field where we have working interests. 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 we 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 and expect the OPUC to review and determine the prudence of this investment in the second half of 2015. Our cumulative investment of approximately $10 million in these additional wells has been accounted for as a utility investment. If regulatory approval is not received, our investment in these additional wells would follow oil and gas accounting.

Table of Contents

The following table outlines our net investment in gas reserves:

In thousands	June 30, 2015	2014	December 31, 2014
Gas reserves, current	$18,214	$20,373	$20,020
Gas reserves, non-current	169,288	157,535	167,190
Less: Accumulated amortization	47,933	27,255	37,910
Total gas reserves[1]	139,569	150,653	149,300
Less: Deferred tax liabilities on gas reserves	27,357	34,828	18,551
Net investment in gas reserves[1]	$112,212	$115,825	$130,749

(1) Gas reserves include our investments in additional wells, subject to regulatory deferral approval with the total gross investment of $10.1 million and $0.5 million at June 30, 2015 and 2014, respectively. Total gas reserves in the additional wells were $8.8 million and $0.5 million and the net investment was $7.9 million and $0.5 million at June 30, 2015 and June 30, 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 our 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.

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, in accordance with the authoritative guidance related to consolidations, 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 are included in other investments on our balance sheet. If we do not develop this investment, then our maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in TWH was $13.4 million at June 30, 2015 and 2014 and December 31, 2014. See Note 12 in our 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 our 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.

Table of Contents

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:

	June 30,		December 31,
In thousands	2015	2014	2014
Natural gas (in therms):			
Financial	350,250	297,925	287,475
Physical	296,250	241,150	420,980
Foreign exchange	$7,920	$10,844	$12,230

Purchased Gas Adjustment (PGA)
As of November 1, 2014, we reached our target hedge percentage for the 2014-15 gas year; hedge transactions are recoverable through the Company's PGA mechanism.

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

	Three Months Ended June 30,			
	2015		2014	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Benefit (expense) to cost of gas	$10,020	$478	$(5,379)	$454
Operating revenues	(616)	—	—	—
Less:				
Amounts deferred to regulatory accounts on the balance sheet	(9,618)	(478)	5,223	(454)
Total loss in pre-tax earnings	$(214)	$—	$(156)	$—

	Six Months Ended June 30,			
	2015		2014	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
(Expense) benefit to cost of gas	$(13,461)	$(263)	$10,533	$179
Operating revenues	22	—	—	—
Less:				
Amounts deferred to regulatory accounts on the balance sheet	13,447	263	(10,652)	(179)
Total gain (loss) in pre-tax earnings	$8	$—	$(119)	$—

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 the 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 $7.9 million and $22.0 million for the three and six months ended June 30, 2015 and a net gain of $4.3 million and $12.8 million for the three and six months ended June 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.

Table of Contents

Credit Risk Management of Financial Derivative Instruments

No collateral was posted with, or by, our counterparties as of June 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 $14.2 million at June 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) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$—	$—	$—	$—	$12,709
Without Adequate Assurance Calls	—	—	—	—	8,767

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our statement of financial position. The Company and its counterparties have the ability to set-off their 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 counterparty, our net derivative position would result in an asset of $1.1 million and a liability of $14.8 million as of June 30, 2015. As of June 30, 2014, our derivative position would have resulted in an asset of $11.5 million and a liability of $0.8 million, and as of December 31, 2014, our 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 our natural gas purchases made on behalf of customers. See Note 13 in our 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 June 30, 2015. As of June 30, 2015 and 2014 and December 31, 2014, the net fair value was a liability of $13.7 million, an asset of $10.7 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 six months ended June 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.

The Company has a Site Remediation and Recovery Mechanism (SRRM) through which NW Natural tracks and has the ability to recover past deferred and future environmental remediation costs. An Order from the OPUC in February 2015 deemed certain environmental remediation expenses and associated carrying costs deferred through March 31, 2014 prudent. The Company's settlement with insurance carriers resulting in insurance proceeds received was also deemed prudent in the Order. Under the Order, NW Natural was required to forego the collection of $15 million out of approximately $95 million of environmental remediation expenses and associated carrying costs it 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. See Note 2 for information regarding the regulatory disallowance of past deferred costs under the Order received from the OPUC in February 2015.

The Company 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 Order, one-third of the proceeds recognized in regulatory accounts are applied to costs deferred through 2012 and the remaining two-thirds is applied to costs over the next 20 years.

Under the SRRM, the Company will recover the first $5 million of annual expense through an amount that will be collected from Oregon customers through a tariff rider. The Company will apply $5 million of insurance (plus interest) to the next portion of environmental expenses each year. Any 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 its authorized Return On Equity (ROE). To the extent the Company earns more than its authorized ROE in a year, the Company is required to cover environmental expenses greater than the $10 million (plus interest from insurance proceeds) with those earnings that exceed its authorized ROE. The Company submitted the required compliance filing demonstrating the proposed implementation of the Order and SRRM on March 31, 2015. The Company is engaged in discussions with the parties to resolve issues they have raised regarding the compliance filing and expects resolution of these matters in the second half of 2015. The 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, the Company requested clarification from the OPUC regarding the amount of insurance proceeds to be held in a secured account. In July 2015, the Company entered into an all-party settlement regarding this issue, which is pending OPUC review and approval. Under the proposed settlement, the Company would accrue interest on the portion of 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 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 that all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such a determination is made.

19

Table of Contents

Environmental Sites

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

	Current Liabilities			Non-Current Liabilities		
	June 30,		December 31,	June 30,		December 31,
In thousands	2015	2014	2014	2015	2014	2014
Portland Harbor site:						
Gasco/Siltronic Sediments	$1,512	$799	$1,767	$38,342	$38,535	$38,019
Other Portland Harbor	1,208	1,317	1,934	4,941	3,080	4,338
Gasco site	5,938	7,152	9,535	37,031	39,553	37,117
Siltronic Uplands site	710	884	957	390	401	348
Central Service Center site	153	70	171	—	190	—
Front Street site	665	1,115	1,020	107	107	122
Oregon Steel Mills	—	—	—	179	179	179
Total	$10,186	$11,337	$15,384	$80,990	$82,045	$80,123

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

	June 30,		December 31,
In thousands	2015	2014	2014
Cumulative cash paid	$119,403	$108,783	$113,740
Total regulatory asset deferral(1)	49,917	52,117	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 NW Natural's Gasco uplands and Siltronic uplands sites. We are a potentially responsible party (PRP) to the Superfund site and we 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). The LWG submitted a draft Feasibility Study (FS) to the EPA in March 2012 that provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is a portion of the costs of the remedy the EPA will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 PRPs. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

GASCO/SILTRONIC SEDIMENTS. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. NW Natural submitted a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA, as well as 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 $39.9 million to $350 million. We have recorded a liability of $39.9 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. NW Natural incurs costs related to its membership in the LWG, who is performing the RI/FS for the EPA. NW Natural also incurs costs related to natural resource damages from these sites. The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource

20

Table of Contents

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 which is 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 draft FS for the Portland Harbor noted above.

GASCO SITE. NW Natural owns 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 us for environmental contamination under the Oregon Department of Environmental Quality (ODEQ) Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site 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 which is 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 which is 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 as of June 30, 2015.

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
NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, NW Natural does not expect the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows. See also Part II, Item 1, “Legal Proceedings.”

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

For additional information regarding other commitments and contingencies, see Note 14 in our 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 six months ended June 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 six 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. Selected subsidiaries are depicted and organized as follows:

We operate in two primary reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as other. We refer to our local gas distribution business as the utility, and our gas storage 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). TWH and our equity investments, TWP and KB Pipeline, are not depicted in the chart above. 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

Table of Contents

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.

EXECUTIVE SUMMARY

Consolidated results include:

	Three Months Ended June 30,				
	2015		2014		
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net income	$2,197	$0.08	$1,071	$0.04	$1,126
Utility margin	70,715		69,795		920
Gas storage operating revenues	5,333		5,038		295

THREE MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Consolidated net income increased $1.1 million primarily due to a $0.9 million increase in utility margin, a $0.3 million increase in gas storage operating revenues, and a $1.2 million decrease in interest expense. These variances were partially offset by a $0.6 million increase in operations and maintenance expense primarily at the utility.

	Six Months Ended June 30,				
	2015		2014		
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net income	$30,683	$1.12	$38,955	$1.43	$(8,272)
Adjustments:					
Regulatory environmental disallowance, net of taxes $5,925[(1)]	9,075	0.33	—	—	9,075
Adjusted consolidated net income[(1)]	$39,758	$1.45	$38,955	$1.43	$803
Utility margin	$201,316		$200,089		$1,227
Gas storage operating revenues	10,636		12,873		(2,237)

(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 six months of 2015.

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Consolidated net income decreased $8.3 million primarily due to the $9.1 million after-tax charge related to the regulatory disallowance associated with a February 2015 OPUC Order in the Company's 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. Other factors were a $1.2 million increase in utility margin, a $4.5 million increase in other income, and a $2.3 million decrease in interest expense, offset by a $2.2 million decrease in gas storage revenues and a $4.3 million increase in operations and maintenance expense.

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

- added more than 10,000 customers over the past twelve months and increased our customer growth rate in the core utility to 1.5%;
- submitted our Combined Heat and Power (CHP) program filing to the OPUC under Senate Bill (SB) 844; and
- continued permitting and land acquisition work on the North Mist gas storage expansion project.

24

Table of Contents

Dividends

Dividend highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
Per common share	2015	2014	2015	2014	Change	Change
Dividends paid	$0.465	$0.460	$0.930	$0.920	$0.005	$0.010

The Board of Directors declared a quarterly dividend on our common stock of $0.465 per share, payable on August 14, 2015, to shareholders of record on July 31, 2015, reflecting an indicated annual dividend rate of $1.86 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 about 5% during the second quarter of 2015, a decrease of about 1% from the same period in 2014. The utility's customer base is over 707,000 customers, reflecting a growth rate of 1.5% on a trailing 12-month basis at June 30, 2015, up from 1.4% at June 30, 2014. We continue to believe our utility is well positioned to add customers and to serve increasing industrial demand as the economy improves, regional business projects move forward, and legislation favoring lower 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 for the Company 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 62% for the upcoming 2015-16 gas year and between 6% and 14% for the following five gas years as of June 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 businesses 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. The 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. Future increases in the demand for natural gas or a decrease in supply can put upward pressure on gas prices and gas price volatility, which could improve the market value for gas storage. Similarly, a decrease in future demand and an increase in supply can cause downward pressure on gas prices and gas price volatility.

Despite current market conditions, we continue to believe in the long-term need for gas storage in California and may see some improvement in gas storage values and an increase in the demand and demand variability for natural gas largely driven by California's renewable portfolio standards and carbon reduction targets. 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 continue to expect shorter contract lengths and prices reflecting current market trends and remain focused on lowering 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. 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:

- Prepaid Pension Asset - On August 3, 2015, the OPUC issued the final Order related to this docket. See "Rate Mechanisms—Pension Cost Deferral and Prepaid Pension Asset" below.
- Gas Reserves - We filed with the OPUC in February 2015 seeking cost recovery on additional investments in gas reserves. See "Rate Mechanisms—Gas Reserves" below.
- 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 - The OPUC opened a new docket to discuss appropriate portfolio hedging across gas utilities in the state. Our request for the OPUC to consider long-term hedging practices will be considered as part of this docket.
- 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.
-

Carbon Solutions Program - SB 844 required the OPUC to develop rules and programs to reduce carbon emissions in Oregon. We anticipate submitting several programs developed under these rules to the OPUC. In June 2015, we submitted our first project related to CHP for OPUC approval. The submitted CHP program would pay owners of new commercial- and industrial-scale CHP systems for verified carbon emissions reductions. SB 844 establishes a six-month review process for these programs; therefore, a final decision is expected by the end of 2015 or at a later time as agreed to by the Company. Additionally, we expect to submit a residential heating conversion program in 2015 to replace fuel oil consumption with cleaner burning natural gas.

Table of Contents

- 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. The Company submitted the required compliance filing on March 31, 2015 and also filed a motion for clarification regarding the amount of insurance proceeds to be held in a secured account. The compliance filing is subject to review and approval by the OPUC, and we are engaged in discussions with the parties to resolve issues they have raised with the filing. We entered into an all-party settlement regarding the secured account, which is currently pending with the OPUC. See "Rate Mechanisms—Environmental Cost Deferral and SRRM."

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.

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. 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, then 33% of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80% deferral option under the PGA, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. 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. The Commission approved it 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 the Company's 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 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 and provides long-term price protection for our utility customers.

On March 28, 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. Accordingly, we filed in 2015 seeking cost recovery for the additional wells drilled in 2014, and we expect the OPUC to review and determine the prudence of this investment in the second half of 2015.

SYSTEM INTEGRITY PROGRAM. Until November of 2014, NW Natural 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

Table of Contents

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 or regulatory assets, 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 continue to recover all bare steel replacement costs through our annual 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 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 for costs deferred between 2003 to 2012.

With respect to recovery of remediation expenses deferred after 2012: (1) The Company will recover the first $5 million of annual expense through a tariff rider from Oregon customers; (2) the Company will apply $5 million of insurance proceeds plus interest to environmental expenses each year; and (3) any expenditures above the $10 million (plus interest) described above would be fully recoverable through the SRRM, to the extent the Company earns at or below its authorized ROE. To the extent the Company earns more than its authorized ROE in a year, the Company is required to cover environmental 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 in three years or earlier if the Company gains greater certainty about its future remediation costs.

The Company submitted the required compliance filing on March 31, 2015 with the OPUC demonstrating the proposed implementation of the Order and SRRM. The Company is engaged in discussions with the parties to resolve issues they have raised regarding the compliance filing and expects resolution of these matters in the second half of 2015. The Company does not currently anticipate a disallowance for 2013 and 2014 based on the earnings test outlined in the Order. The compliance filing is subject to review and final 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, the Company requested clarification from the OPUC regarding the amount of insurance proceeds to be held in a secured account. In July 2015, the Company entered into an all-party settlement regarding this issue, which is pending OPUC review and approval. Under the proposed settlement, the Company would accrue interest on the portion of 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 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 January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding.

Table of Contents

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 (FAS 87 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 $4.3 million for the three and six months ended June 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. On August 3, 2015, the OPUC issued the final Order, which confirmed the use of accounting expense (FAS 87 expense) for recovery of pension expense, but denied the utilities' request to include prepaid pension assets in rates. Although the Company will not recover the financing costs associated with the prepaid asset, there will be no impact to earnings from this Order. The Company will continue collecting pension expense based on the amounts set in its 2003 Oregon general rate case and will continue deferring the difference between actual pension expense and collected expense in its pension balancing account.

CUSTOMER CREDITS FOR GAS STORAGE AND ASSET MANAGEMENT SHARING. In the second quarter of 2015, the Company received regulatory approval to provide an interstate storage credit of $9.6 million to its 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 the Company 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 June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	QTR Change	YTD Change
Utility net income	$2,245	$2,205	$30,580	$38,224	$40	$(7,644)
EPS - utility segment	$0.08	$0.08	$1.12	$1.41	$—	$(0.29)
Gas sold and delivered (therms)	207,886	208,253	537,863	614,470	(367)	(76,607)
Utility margin[1]	$70,715	$69,795	$201,316	$200,089	$920	$1,227

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

THREE MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Utility net income was slightly higher due to the following:

- a $0.9 million increase in utility margin primarily due to:
  - a $2.0 million increase from customer growth, added loads under higher commercial rate schedules, and rate-base returns on certain investments;
  - a $0.8 million increase from gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA; offset by
  - a $1.9 million decrease from a number of other items primarily related to cost deferrals.
- a $0.7 million decrease in interest expense due to the redemption of $100 million of utility FMBs over the last twelve months; and
- a $1.5 million increase in operations and maintenance expense primarily due to higher compensation and benefit expense.

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Utility net income decreased $7.6 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 $1.2 million increase in utility margin primarily due to:
  - a $3.5 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 $3.8 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 $1.9 million decrease from a number of other items primarily related to cost deferrals.
- a $1.0 million net negative impact from the following offsetting items: an increase in other income, a decrease in interest expense, and an increase in operations and maintenance, depreciation, and general tax expense.

Total utility volumes sold and delivered in the three months ended June 30, 2015 decreased slightly over the same period of 2014. For the six months ended June 30 2015, volumes decreased 12% compared to the six months ended June 30, 2014 due to the impact of 18% warmer weather.

30

Table of Contents

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 June 30, 2015	2014	Six months ended June 30, 2015	2014	Favorable/ (Unfavorable) QTD	YTD
Utility volumes (therms):						
Residential and commercial sales	97,066	96,533	303,883	370,689	533	(66,806)
Industrial sales and transportation	110,820	111,720	233,980	243,781	(900)	(9,801)
Total utility volumes sold and delivered	207,886	208,253	537,863	614,470	(367)	(76,607)
Utility operating revenues:						
Residential and commercial sales	$117,919	$113,186	$358,831	$383,188	$4,733	$(24,357)
Industrial sales and transportation	17,138	16,855	37,664	38,367	283	(703)
Other revenues	1,131	1,166	2,537	2,643	(35)	(106)
Less: Revenue taxes	3,297	3,132	9,835	10,628	165	(793)
Total utility operating revenues	132,891	128,075	389,197	413,570	4,816	(24,373)
Less: Cost of gas	62,176	58,280	187,881	213,481	3,896	(25,600)
Utility margin	$70,715	$69,795	$201,316	$200,089	$920	$1,227
Utility margin:[1]						
Residential and commercial sales	$61,940	$62,468	$182,312	$184,572	$(528)	$(2,260)
Industrial sales and transportation	7,258	6,707	14,832	15,191	551	(359)
Miscellaneous revenues	1,133	1,279	2,539	2,866	(146)	(327)
Gain (loss) from gas cost incentive sharing	340	(430)	1,561	(2,261)	770	3,822
Other margin adjustments	44	(229)	72	(279)	273	351
Utility margin	$70,715	$69,795	$201,316	$200,089	$920	$1,227
Degree days:						
Average[2]	691	691	2,546	2,546	—	—
Actual degree days	512	530	1,993	2,420	(3)%	(18)%
Percent colder (warmer) than average weather[2]	(26)%	(23)%	(22)%	(5)%		

Customers - end of period:	As of June 30, 2015	2014	Change	% Change
Residential customers	640,581	630,868	9,713	1.5 %
Commercial customers	66,036	65,619	417	0.6
Industrial customers	922	935	(13)	(1.4)
Total number of customers	707,539	697,422	10,117	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 June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	QTR Change	YTD Change
Utility volumes (therms):						
Residential sales	56,655	56,059	186,715	229,236	596	(42,521)
Commercial sales	40,411	40,474	117,168	141,453	(63)	(24,285)
Total volumes	97,066	96,533	303,883	370,689	533	(66,806)
Utility operating revenues:						
Residential sales	$75,775	$72,230	$236,312	$252,212	$3,545	$(15,900)
Commercial sales	42,144	40,956	122,519	130,976	1,188	(8,457)
Total operating revenues	$117,919	$113,186	$358,831	$383,188	$4,733	$(24,357)
Utility margin:						
Residential:						
Sales	$39,764	$39,444	$110,540	$127,952	$320	$(17,412)
Weather normalization adjustments	139	1,663	12,492	489	(1,524)	12,003
Decoupling adjustments	2,964	1,542	4,169	407	1,422	3,762
Total residential utility margin	42,867	42,649	127,201	128,848	218	(1,647)
Commercial:						
Sales	16,506	17,359	44,261	52,307	(853)	(8,046)
Weather normalization adjustments	(29)	752	5,215	296	(781)	4,919
Decoupling adjustments	2,596	1,708	5,635	3,121	888	2,514
Total commercial utility margin	19,073	19,819	55,111	55,724	(746)	(613)
Total utility margin	$61,940	$62,468	$182,312	$184,572	$(528)	$(2,260)

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

- sales volumes increased 0.5 million therms primarily due to customer growth;
- operating revenues increased $4.7 million primarily due to a 6% increase in average cost of gas; and
- utility margin decreased $0.5 million reflecting several individually insignificant decreases offset by increases from commercial and residential customer growth, added loads under higher commercial rate schedules, and added rate-base returns on certain investments.

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

- sales volumes decreased 66.8 million therms primarily due to 18% warmer weather compared to prior year;
- operating revenues decreased $24.4 million primarily due to 18% warmer weather, partially offset by a 6% increase in average cost of gas; and
- utility margin decreased $2.3 million primarily due to the effects of warmer weather on customers that are 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 decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select

Table of Contents

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 June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2015	2014	2015	2014	Change	Change
Volumes (therms):						
Industrial - firm sales	7,305	7,427	15,956	17,565	(122)	(1,609)
Industrial - firm transportation	34,796	35,666	75,624	79,826	(870)	(4,202)
Industrial - interruptible sales	20,853	23,264	37,245	41,683	(2,411)	(4,438)
Industrial - interruptible transportation	47,866	45,363	105,155	104,707	2,503	448
Total volumes	110,820	111,720	233,980	243,781	(900)	(9,801)
Utility margin:						
Industrial - firm and interruptible sales	$3,165	$2,872	$6,382	$6,596	$293	$(214)
Industrial - firm and interruptible transportation	4,093	3,835	8,450	8,595	258	(145)
Total utility margin	$7,258	$6,707	$14,832	$15,191	$551	$(359)

THREE MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Industrial sales and transportation volumes decreased 0.9 million therms, while industrial margins increased by $0.6 million or 8%. The volume decrease was primarily due to lower usage from a customer and the impact of warmer weather, while the margin increase was largely due to an increase in industrial customers under higher margin rate schedules.

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Industrial sales and transportation volumes decreased 9.8 million therms, while industrial margins decreased by $0.4 million compared to last year. The volume decrease was primarily due to lower usage from warmer weather, while the margin decrease was largely due to higher fee revenues in the prior year from increased usage and other charges resulting from the cold weather event in February 2014.

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 gas reserves, which is 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.

33

Table of Contents

Cost of gas highlights include:

In thousands, except as noted	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014	QTR Change	YTD Change
Cost of gas	$62,176	$58,280	$187,881	$213,481	$3,896	$(25,600)
Volumes sold (therms)[1]	118,633	118,999	350,493	421,712	(366)	(71,219)
Average cost of gas (cents per therm)[1]	$0.52	$0.49	$0.54	$0.51	$0.03	0.03
Gain (loss) from gas cost incentive sharing	340	(430)	1,561	(2,261)	770	3,822

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

THREE MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Cost of gas increased $3.9 million or 7% primarily due to a 6% increase in average cost of gas.

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Cost of gas decreased $25.6 million or 12% primarily due to a 17% 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, the Company 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 June 30, 2015	2014	Six Months Ended June 30, 2015	2014	QTR Change	YTD Change
Gas storage net income (loss)	$(86)	$(1,157)	$28	$470	$1,071	$(442)
EPS - gas storage segment	—	(0.04)	—	0.02	0.04	(0.02)
Operating revenues	5,333	5,038	10,636	12,873	295	(2,237)
Operating expenses	4,594	5,523	8,842	9,805	(929)	(963)

THREE MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Gas storage net loss decreased $1.1 million due to a $0.3 million increase in operating revenues from slightly higher contract prices for the 2015-16 gas storage year and a $0.9 million decrease in operating expenses due to lower repair and power costs at our Gill Ranch facility.

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Gas storage net income decreased $0.4 million due to a $2.2 million decrease in operating revenues mainly due to lower contract prices for the 2014-15 gas storage year offset by a $1.0 million decrease in operating expenses due to lower repair and power costs at our Gill Ranch facility. 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.

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 these conditions, we

Table of Contents

continue to believe in the long-term need for gas storage in California and have recently seen a slight increase in contracting prices for the 2015-16 gas storage year. 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 may contribute to higher summer/winter natural gas price spreads, gas price volatility, and gas storage values. 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 of the Company 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 June 30, 2015 and 2014. For the six months ended June 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 June 30, 2015	2014	Six Months Ended June 30, 2015	2014	QTR Change	YTD Change
Operations and maintenance	$35,311	$34,731	$89,427	$70,117	$580	$19,310

THREE MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Operations and maintenance expense increased $0.6 million due to the following:

- a $2.2 million increase in compensation and benefit expense including increased pension and employee incentive costs, as well as higher wage rates under the new union labor contract, which became effective June 1, 2014; offset by
- a $1.3 million decrease related to 2014 repair and power costs at our Gill Ranch gas storage facility; and
- a $0.3 million decrease in non-payroll costs primarily associated with contract work and professional services.

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Operations and maintenance expense increased $19.3 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. The Company also expensed an additional $1 million related to the Order; and
- a $4.0 million increase in compensation and benefit expense including increased health care, pension, and employee incentive costs, as well as higher wage rates under the new union labor contract, which became effective June 1, 2014; and
- a $1.1 million increase in non-payroll costs primarily associated with ongoing growth initiatives and facilities costs; offset by
- a $1.8 million decrease related to 2014 repair and power costs at our Gill Ranch gas storage facility.

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

Other Operating Expenses

General taxes increased $0.5 million and $1.0 million for the three and six months ended June 30, 2015, respectively, compared to the same periods in 2014 primarily due to increases in Oregon property taxes and local business license taxes. Depreciation expense increased $0.5 million and $1.0 million for the three and six months ended June 30, 2015, respectively, compared to the same respective periods in 2014, as a result of planned capital expenditures. See "Financial Condition—Cash Flows—Investing Activities" below for additional information.

Table of Contents

Other Income and Expense, Net

Other income and expense, net highlights include:

In thousands	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014	QTR Change	YTD Change
Other income and expense, net	$1,135	$262	$6,184	$1,645	$873	$4,539

THREE MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Other income increased $0.9 million primarily due to a decrease in regulatory interest expense from the application of insurance proceeds under the SRRM.

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Other income increased $4.5 million due to the recognition of net $5.3 million related to the equity component in interest income from our deferred environmental expenses. We realized the equity component of interest 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 $0.8 million increase in regulatory interest expense primarily related to the receipt of insurance proceeds in the first quarter of 2014.

Interest Expense

Interest expense highlights include:

In thousands	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014	QTR Change	YTD Change
Interest expense	$10,438	$11,677	$20,919	$23,219	$(1,239)	$(2,300)

THREE AND SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Interest expense decreased $1.2 million for the quarter and $2.3 million for the six 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:

In thousands	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014	QTR Change	YTD Change
Income tax expense	$1,414	$780	$20,497	$27,765	$634	$(7,268)

THREE AND SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Increases or decreases in income tax expense are correlated with changes in pre-tax income.

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 capital markets at reasonable costs. Our consolidated capital structure was as follows:

	June 30,				December 31,	
	2015		2014		2014	
Common stock equity	48.9	%	49.2	%	46.1	%
Long-term debt	39.1		39.7		37.4	
Short-term debt, including any current maturities of long-term debt	12.0		11.1		16.5	
Total	100.0	%	100.0	%	100.0	%

Liquidity and Capital Resources

At June 30, 2015, we had $4.5 million of cash and cash equivalents compared to $17.2 million at June 30, 2014. We also had $4.5 million and $3.0 million in restricted cash at Gill Ranch at June 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 June 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 June 30, 2015. However, if the credit risk-related contingent features underlying these contracts were triggered on June 30, 2015, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $12.7 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 maintain a debt reserve account, which is currently $4.5 million, 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 must receive common equity contributions from its parent NWN Gas Storage of at least $2 million by August 31, 2015 and 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 NW Natural 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 the Company's liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing, and financing activities discussed below.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities. See “Credit Agreements” below. At June 30, 2015 and 2014, our utility had commercial paper outstanding of $190.3 million and $74.2 million, respectively. The effective interest rate on the utility’s commercial paper outstanding at June 30, 2015 and 2014 was 0.4% and 0.2%, respectively.

38

Table of Contents

Credit Agreements

NW Natural has a $300 million revolving credit facility, with a feature that allows the Company to request increases in the total commitment amount, up to a maximum of $450 million. The final maturity date of the agreement is December 20, 2019.

All lenders under the agreement are major financial institutions with committed balances and investment grade credit ratings as of June 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, the Company does 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 June 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 June 30, 2015 and 2014, with consolidated indebtedness to total capitalization ratios of 51.1% and 50.8%, 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. Our 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.

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 12 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.

39

Table of Contents

Cash Flows

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

Operating activity highlights include:

	Six Months Ended June 30,		
In thousands	2015	2014	Change
Cash provided by operating activities	$167,484	$233,245	$(65,761)

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Operating cash flows decreased $65.8 million due to the following:

- a decrease of $97.8 million in deferred environmental recoveries reflecting insurance settlements totaling approximately $91 million received in the first quarter of 2014, which did not recur in 2015;
- a decrease of $8.7 million from changes in accrued taxes, which reflected lower earnings in the current year and environmental proceeds which were included in taxable income in the first quarter of 2014;
- a decrease of $13.1 million from changes in accounts payable due to fewer gas purchases as a result of warmer weather in the first six months of 2015 compared to 2014 when we were refilling gas storage after a cold winter;
- a $15.0 million non-cash regulatory disallowance of prior environmental cost deferrals in 2015; and
- an increase of $40.5 million for deferred gas costs, net due to lower actual gas prices than prices embedded in the PGA compared to the prior year.

The non-cash pension expense recognized on the income statement for the six months ended June 30, 2015 was $3.0 million, compared to $2.5 million for the same period in 2014. Although we expect gross non-cash pension expense to increase in the coming years, these increases will be 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 six months ended June 30, 2015, we contributed $5.8 million to our utility's qualified defined benefit pension plan, compared to $6.0 million for the same period in 2014. We plan to make $9.2 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 June 30, 2015, an income tax payable balance of $1.8 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 in 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.

40

Table of Contents

Investing Activities

Investing activity highlights include:

In thousands	Six Months Ended June 30, 2015	2014	Change
Total cash used in investing activities	$(61,316)	$(71,164)	$9,848
Capital expenditures	(58,072)	(52,489)	(5,583)
Utility gas reserves	(1,945)	(18,632)	16,687

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Investing cash flows decreased $9.8 million due to lower investments in utility gas reserves, partially offset by higher capital expenditures at the utility.

Under the amended gas reserves agreement, NW Natural ended its original drilling program with Encana, but increased the Company's 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 approximately $20 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, we 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 our receipt of permits and certain land rights needed for the project.

Financing Activities

Financing activity highlights include:

In thousands	Six Months Ended June 30, 2015	2014	Change
Total cash used in financing activities	$(111,236)	$(154,312)	$43,076
Change in short-term debt	(44,400)	(114,000)	69,600
Long-term debt retired	(40,000)	(20,000)	(20,000)

SIX MONTHS ENDED JUNE 30, 2015 COMPARED TO JUNE 30, 2014. Financing cash flows decreased $43.1 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 in the second quarter of 2015 compared to $20 million retired at Gill Ranch in the same period of 2014.

41

Table of Contents

Ratios of Earnings to Fixed Charges

For the six and twelve months ended June 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 3.32, 2.89, 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 June 30, 2015, we had a net regulatory asset of $49.9 million for deferred environmental costs, which includes deferred payments and interest of $58.4 million and $91.2 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 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 six month period ended June 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 June 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 June 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
04/01/15 - 04/30/15	—	$—	—	—
05/01/15 - 05/31/15	3,409	44.41	—	—
06/01/15 - 06/30/15	—	—	—	—
Total	3,409	$44.41	2,124,528	$ 16,732,648

(1) During the quarter ended June 30, 2015, 3,409 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended June 30, 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 June 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.

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: August 4, 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 June 30, 2015

Exhibit Number	Document
12	Statement Re: Computation of Ratios of Earnings to Fixed Charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended June 30, 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.