NORTHWEST NATURAL GAS CO
Form 10-Q
August 02, 2016

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, 2016

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 22, 2016, 27,550,206 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, 2016

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FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as anticipates, assumes, 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, projections, forecasts and predictions;
- objectives, goals and strategies;
- assumptions and estimates;
- future events or performance;
- trends, timing and cyclicality;
- risks;
- earnings and dividends;
- capital and other expenditures and allocation;
- capital structure;
- growth and profitability;
- customer rates;
- commodity costs and volumes;
- gas reserves, volumes, investment and recovery;
- operational and maintenance performance and costs;
- energy policy and preferences;
- efficacy of and exposure under derivatives and hedges;
- liquidity, funding sources, and financial positions;
- project and program development, expansion, or investment;
- competition;

- costs of compliance;
- credit exposures;
- regulatory outcomes, prudency or recovery;
- impacts of laws, rules and regulations;
- tax positions, liabilities or refunds;
- levels and pricing of gas storage contracts and gas storage markets;
- outcomes and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations and contributions under retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- effects of new or anticipated changes in accounting standards or pronouncements;
- approval and adequacy of regulatory deferrals;
- effects and efficacy of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs, allocations and recoveries, and 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 operational or financial performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2015 Annual Report on Form 10-K, Part I, Item 1A "Risk

Factors" and Part II, Item 7 and Item 7A, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures about Market Risk," and in Part I, Items 2 and 3, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk," and Part II, Item 1A, "Risk Factors," herein.

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

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ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
In thousands, except per share data	2016	2015	2016	2015
Operating revenues	$99,183	$138,280	$354,712	$399,945
Operating expenses:				
Cost of gas	20,871	62,176	129,282	187,881
Operations and maintenance	35,962	35,311	74,901	89,427
Environmental remediation	1,893	—	6,922	—
General taxes	7,438	7,649	16,122	16,381
Depreciation and amortization	20,413	20,230	40,807	40,341
Total operating expenses	86,577	125,366	268,034	334,030
Income from operations	12,606	12,914	86,678	65,915
Other income (expense), net	513	1,135	(1,796)	6,184
Interest expense, net	9,718	10,438	19,454	20,919
Income before income taxes	3,401	3,611	65,428	51,180
Income tax expense	1,382	1,414	26,768	20,497
Net income	2,019	2,197	38,660	30,683
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $126 and $217 for the three months ended and $253 and $433 for the six months ended June 30, 2016 and 2015, respectively	143	331	337	663
Comprehensive income	$2,162	$2,528	$38,997	$31,346
Average common shares outstanding:				
Basic	27,510	27,343	27,479	27,322
Diluted	27,632	27,388	27,591	27,378
Earnings per share of common stock:				
Basic	$0.07	$0.08	$1.41	$1.12
Diluted	0.07	0.08	1.40	1.12
Dividends declared per share of common stock	0.4675	0.4650	0.9350	0.9300

See Notes to Unaudited Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2016	June 30, 2015	December 31, 2015
Assets:			
Current assets:			
Cash and cash equivalents	$5,463	$4,466	$4,211
Accounts receivable	23,353	32,041	68,228
Accrued unbilled revenue	14,175	12,760	57,987
Allowance for uncollectible accounts	(570)	(723)	(870)
Regulatory assets	49,004	63,016	69,178
Derivative instruments	7,445	1,023	2,719
Inventories	66,171	76,511	70,868
Gas reserves	15,707	18,214	17,094
Income taxes receivable	—	—	7,900
Deferred tax assets	—	12,693	—
Other current assets	21,312	14,007	33,460
Total current assets	202,060	234,008	330,775
Non-current assets:			
Property, plant, and equipment	3,146,631	3,042,671	3,089,380
Less: Accumulated depreciation	932,179	893,722	906,717
Total property, plant, and equipment, net	2,214,452	2,148,949	2,182,663
Gas reserves	108,286	121,355	114,552
Regulatory assets	344,969	342,806	370,711
Derivative instruments	3,541	1,369	27
Other investments	67,868	68,147	68,066
Restricted cash	—	4,500	—
Other non-current assets	1,968	2,782	2,616
Total non-current assets	2,741,084	2,689,908	2,738,635
Total assets	$2,943,144	$2,923,916	$3,069,410

See Notes to Unaudited Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2016	June 30, 2015	December 31, 2015
Liabilities and equity:			
Current liabilities:			
Short-term debt	$152,800	$190,300	$270,035
Current maturities of long-term debt	24,987	—	24,973
Accounts payable	57,756	49,505	73,219
Taxes accrued	6,237	8,782	10,420
Interest accrued	5,793	5,922	5,873
Regulatory liabilities	27,300	26,712	29,927
Derivative instruments	3,471	15,017	22,092
Other current liabilities	35,289	31,332	41,148
Total current liabilities	313,633	327,570	477,687
Long-term debt	570,045	613,737	569,445
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	554,400	524,099	530,021
Regulatory liabilities	341,259	328,646	339,287
Pension and other postretirement benefit liabilities	219,049	233,554	223,105
Derivative instruments	474	1,077	3,447
Other non-current liabilities	144,285	118,269	145,446
Total deferred credits and other non-current liabilities	1,259,467	1,205,645	1,241,306
Commitments and contingencies (See Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,550, 27,363, and 27,427 at June 30, 2016 and 2015 and December 31, 2015, respectively	388,967	378,887	383,144
Retained earnings	417,857	407,490	404,990
Accumulated other comprehensive loss	(6,825)	(9,413)	(7,162)
Total equity	799,999	776,964	780,972
Total liabilities and equity	$2,943,144	$2,923,916	$3,069,410

See Notes to Unaudited Consolidated Financial Statements

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

	Six Months Ended June 30,	
In thousands	2016	2015
Operating activities:		
Net income	$38,660	$30,683
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	40,807	40,341
Regulatory amortization of gas reserves	7,647	10,023
Deferred tax liabilities, net	27,022	6,886
Qualified defined benefit pension plan expense	2,737	3,032
Contributions to qualified defined benefit pension plans	(6,120)	(5,810)
Deferred environmental expenditures	(5,521)	(5,659)
Regulatory disallowance of prior environmental cost deferrals	3,273	15,000
Interest income on deferred environmental expenses	—	(5,322)
Amortization of environmental remediation	6,922	—
Other	2,121	418
Changes in assets and liabilities:		
Receivables, net	87,271	85,121
Inventories	4,525	1,321
Taxes accrued	3,710	(249)
Accounts payable	(17,141)	(37,532)
Interest accrued	(80)	(157)
Deferred gas costs	(9,295)	21,718
Other, net	13,022	7,670
Cash provided by operating activities	199,560	167,484
Investing activities:		
Capital expenditures	(62,153)	(58,072)
Utility gas reserves	—	(1,945)
Restricted cash	—	(1,500)
Other	2,453	201
Cash used in investing activities	(59,700)	(61,316)
Financing activities:		
Common stock issued, net	4,332	812
Long-term debt retired	—	(40,000)
Change in short-term debt	(117,235)	(44,400)
Cash dividend payments on common stock	(25,677)	(25,398)
Other	(28)	(2,250)
Cash used in financing activities	(138,608)	(111,236)
Increase (decrease) in cash and cash equivalents	1,252	(5,068)
Cash and cash equivalents, beginning of period	4,211	9,534
Cash and cash equivalents, end of period	$5,463	$4,466
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalization	$18,124	$19,615
Income taxes paid (refunded), net	(7,900)	4,625

See Notes to Unaudited Consolidated Financial Statements

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

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the 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 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 2015 Annual Report on Form 10-K (2015 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.

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

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2. SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are described in Note 2 of the 2015 Form 10-K. There were no material changes to those accounting policies during the six months ended June 30, 2016. The following are current updates to certain critical accounting policy estimates and new accounting standards.

Industry Regulation

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the Public Utility Commission of Oregon (OPUC) or Washington Utilities and Transportation Committee (WUTC), which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a rate of return or a carrying charge in certain cases.

Amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	June 30,		December 31,
In thousands	2016	2015	2015
Current:			
Unrealized loss on derivatives(1)	$3,439	$15,017	$22,092
Gas costs	9,571	19,070	8,717
Environmental costs(2)	9,610	—	9,270
Decoupling(3)	14,170	17,736	18,775
Other(4)	12,214	11,193	10,324
Total current	$49,004	$63,016	$69,178
Non-current:			
Unrealized loss on derivatives(1)	$474	$1,077	$3,447
Pension balancing(5)	48,761	38,255	43,748
Income taxes	40,106	44,767	43,049
Pension and other postretirement benefit liabilities	177,596	193,356	184,223
Environmental costs(2)	65,983	49,917	76,584
Gas costs	1,487	2,472	1,949
Decoupling(3)	1,776	3,186	6,349
Other(4)	8,786	9,776	11,362
Total non-current	$344,969	$342,806	$370,711

	Regulatory Liabilities		
	June 30,		December 31,
In thousands	2016	2015	2015
Current:			
Gas costs	$12,501	$20,087	$14,157
Unrealized gain on derivatives(1)	7,428	1,015	2,659
Other(4)	7,371	5,610	13,111
Total current	$27,300	$26,712	$29,927
Non-current:			
Gas costs	$1,622	$3,615	$8,869
Unrealized gain on derivatives(1)	3,541	1,369	27
Accrued asset removal costs(6)	332,627	320,206	327,047
Other(4)	3,469	3,456	3,344

Total non-current	$341,259	$328,646	$339,287

(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.

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(2) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and 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, recovery of deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from Oregon customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million tariff rider. The amounts allocable to Oregon are recoverable through utility rates, subject to an earnings test. See Note 13.

(3) This deferral represents the margin adjustment resulting from differences between actual and expected volumes.

(4) 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.

(5) 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 interest income recognized when amounts are collected in rates.

(6) Estimated costs of removal on certain regulated properties are collected through rates.

We believe all costs incurred and deferred at June 30, 2016 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write-off the net unrecoverable balances in the period such determination is made.

New Accounting Standards

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.

Recently Adopted Accounting Pronouncements

BENEFIT PLAN ACCOUNTING. On July 31, 2015, the FASB issued ASU 2015-12, "Plan Accounting: Defined Benefit Pension Plans, Defined Contribution Pension Plans, and Health and Welfare Benefit Plans." The ASU outlines a three part update. Only part two of the update is applicable for us, which simplifies the investment disclosure requirements for employee benefit plans by allowing certain disclosures at an aggregated level, reducing the number of ways assets must be grouped and analyzed, and no longer requiring investment strategy disclosures for certain investments. The new requirements were effective for us beginning January 1, 2016 and will be applied retrospectively in the 2016 Form 10-K, for all periods presented. This ASU will not materially affect our financial statements and disclosures, but will change certain presentation and disclosures within our pension and other postretirement benefit plan footnote in our 2016 Form 10-K, for all periods presented.

FAIR VALUE MEASUREMENT. On May 1, 2015, the FASB issued ASU 2015-07, "Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)." The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements were effective for us beginning January 1, 2016 and will be applied retrospectively to all periods presented, in our 2016 Form 10-K. This ASU will not materially affect our financial statements and disclosures, but will change certain presentation and disclosure of the fair value of certain plan assets in our pension and other postretirement benefit plan disclosures in our 2016 Form 10-K, for all periods presented.

INTANGIBLES - GOODWILL AND OTHER INTERNAL-USE SOFTWARE. On April 15, 2015 the FASB issued ASU 2015-05, "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement." The ASU provides customers guidance on how to determine whether a cloud computing arrangement includes a software license. The new requirements were effective for us beginning January 1, 2016. We will apply the guidance prospectively as contracts arise and do not expect the ASU to materially affect our financial statements and disclosures.

DEBT ISSUANCE COSTS. On April 7, 2015, the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs," which requires the presentation of debt issuance costs in the balance sheet as a direct deduction from the associated debt liability. The new requirements were effective for us beginning January 1, 2016. The new guidance has been applied on a retrospective basis and is reflected in our consolidated balance sheets and Note 6.

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Recently Issued Accounting Pronouncements

STOCK BASED COMPENSATION. On March 30, 2016, the FASB issued ASU 2016-09, "Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting." The ASU changes how companies account for certain aspects of share-based payment awards to employees, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The amendments in this standard are effective for us beginning January 1, 2017. Early adoption is permitted in any interim or annual period. We are currently assessing the effect of this standard and do not expect this standard to materially affect our financial statements and disclosures.

LEASES. On February 25, 2016, the FASB issued ASU 2016-02, "Leases," which revises the existing lease accounting guidance. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases that are greater than 12 months at lease commencement, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Lessor accounting will remain substantially the same under the new standard. Quantitative and qualitative disclosures are also required for users of the financial statements to have a clear understanding of the nature of our leasing activities. The standard is effective for us beginning January 1, 2019, and early adoption is permitted. The new standard must be adopted using a modified retrospective transition and provides for certain practical expedients. Transition will require application of the new guidance at the beginning of the earliest comparative period presented. We are currently assessing the effect of this standard on our financial statements and disclosures.

FINANCIAL INSTRUMENTS. On January 5, 2016, the FASB issued ASU 2016-01, "Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities." The ASU enhances the reporting model for financial instruments, which includes amendments to address aspects of recognition, measurement, presentation, and disclosure. The new standard is effective for us beginning January 1, 2018. Upon adoption, we will be required to make a cumulative-effect adjustment to the consolidated balance sheet in the first quarter of 2018. Early adoption is permitted, and we are currently assessing the effect of this standard on our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The ASU also prescribes 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 August 12, 2015, the FASB deferred the effective date by one year to January 1, 2018 for annual reporting periods beginning after December 15, 2017. The FASB also permitted early adoption of the standard, but not before the original effective date of January 1, 2017. We plan to adopt the new standard effective January 1, 2018 and are assessing the effect this standard will have on our financial statements and disclosures.

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3. EARNINGS PER SHARE

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2016	2015	2016	2015
Net income	$2,019	$2,197	$38,660	$30,683
Average common shares outstanding - basic	27,510	27,343	27,479	27,322
Additional shares for stock-based compensation plans (See Note 5)	122	45	112	56
Average common shares outstanding - diluted	27,632	27,388	27,591	27,378
Earnings per share of common stock - basic	$0.07	$0.08	$1.41	$1.12
Earnings per share of common stock - diluted	$0.07	$0.08	$1.40	$1.12
Additional information:				
Antidilutive shares	23	35	16	27

4. SEGMENT INFORMATION

We primarily operate in two reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which are aggregated and reported as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes the utility portion of our Mist underground storage facility in Oregon and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp. Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Other includes NNG Financial and NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project. See Note 4 in the 2015 Form 10-K for further discussion of our segments.

Inter-segment transactions were insignificant for the periods presented. The following table presents summary financial information concerning the reportable segments:

	Three Months Ended June 30,			
In thousands	Utility	Gas Storage	Other	Total
2016				
Operating revenues	$92,135	$6,992	$ 56	$99,183
Depreciation and amortization	18,961	1,452	—	20,413
Income from operations	9,714	2,879	13	12,606
Net income	507	1,439	73	2,019
Capital expenditures	31,295	804	—	32,099
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

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In thousands	Six Months Ended June 30, Utility	Gas Storage	Other	Total
2016				
Operating revenues	$342,239	$12,361	$ 112	$354,712
Depreciation and amortization	37,721	3,086	—	40,807
Income from operations	82,009	4,605	64	86,678
Net income	36,359	2,175	126	38,660
Capital expenditures	60,472	1,681	—	62,153
Total assets at June 30, 2016	2,663,817	263,498	15,829	2,943,144
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	2,638,569	270,434	14,913	2,923,916
Total assets at December 31, 2015	2,792,736	261,750	14,924	3,069,410

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes, the associated cost of gas, and environmental recovery revenues. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. Environmental recovery revenues represent collections received from customers through our environmental recovery mechanism in Oregon. These collections are offset by the amortization of environmental liabilities, which is presented as environmental remediation expense in our operating expenses. By subtracting cost of gas and environmental remediation expense 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 and other segments 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:

In thousands	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Utility margin calculation:				
Utility operating revenues[(1)]	$92,135	$132,891	$342,239	$389,197
Less: Utility cost of gas	20,871	62,176	129,282	187,881
Environmental remediation expense	1,893	—	6,922	—
Utility margin	$69,371	$70,715	$206,035	$201,316

(1) Utility operating revenues include environmental recovery revenues, which are collections received from customers through our environmental recovery mechanism in Oregon, offset by environmental remediation expense. Collections under this mechanism began in November 2015.

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5. STOCK-BASED COMPENSATION

Our stock-based compensation plans are designed to promote stock ownership in NW Natural by employees and officers. These compensation plans include a Long-Term Incentive Plan (LTIP), an Employee Stock Purchase Plan (ESPP), and a Restated Stock Option Plan. For additional information on our stock-based compensation plans, see Note 6 in the 2015 Form 10-K and the updates provided below.

Long-Term Incentive Plan

Performance Shares

LTIP performance shares incorporate a combination of market, performance, and service-based factors. During the six months ended June 30, 2016, 36,259 performance-based shares were granted under the LTIP based on target-level awards with a weighted-average grant date fair value of $50.13 per share. As of June 30, 2016, there was $3.2 million of unrecognized compensation cost from LTIP grants, which is expected to be recognized through 2018. 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	$50.15	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.4675	
Expected dividend yield	3.7	%
Dividend discount factor	0.9010	

Restricted Stock Units (RSUs)

During the six months ended June 30, 2016, 32,711 RSUs were granted under the LTIP with a weighted-average grant date fair value of $52.68 per share. The fair value of a RSU is equal to the closing market price of our common stock on the grant date. As of June 30, 2016, there was $3.4 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2020. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of four years from the grant date. A RSU obligates us, 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, 2016, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 67 days and an average maturity of 35 days and an outstanding balance of $152.8 million. The carrying cost of our commercial paper approximates fair value using Level 2 inputs, due to the short-term nature of the notes. See Note 2 in the 2015 Form 10-K for a description of the fair value hierarchy.

Long-Term Debt

At June 30, 2016, we had long-term debt of $595.0 million, which included $6.7 million of unamortized debt issuance costs. 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%.

Fair Value of Long-Term Debt

Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using inputs from utility companies with similar credit ratings, whose debt trades actively in public markets and has terms and remaining maturities comparable to our own debt. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2 in the 2015 Form 10-K for a description of the fair value hierarchy.

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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	2016	2015	2015
Gross long-term debt	$601,700	$621,700	$601,700
Unamortized debt issuance costs	(6,668)	(7,963)	(7,282)
Carrying amount	$595,032	$613,737	$594,418
Estimated fair value[1]	708,322	695,902	667,168

(1) Estimated fair value does not include unamortized debt issuance costs.

7. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
In thousands	2016	2015	2016	2015	2016	2015	2016	2015
Service cost	$1,944	$2,309	$121	$145	$3,888	$4,618	$242	$290
Interest cost	4,574	4,595	300	292	9,148	9,190	600	583
Expected return on plan assets	(5,017)	(5,174)	—	—	(10,034)	(10,348)	—	—
Amortization of net actuarial loss	3,502	4,561	192	125	7,004	9,122	384	251
Amortization of prior service costs	58	58	(117)	49	116	116	(234)	98
Net periodic benefit cost	5,061	6,349	496	611	10,122	12,698	992	1,222
Amount allocated to construction	(1,574)	(1,879)	(164)	(198)	(3,122)	(3,704)	(328)	(389)
Amount deferred to regulatory balancing account[1]	(1,593)	(2,165)	—	—	(3,220)	(4,340)	—	—
Net amount charged to expense	$1,894	$2,305	$332	$413	$3,780	$4,654	$664	$833

(1) The deferral of defined benefit pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account. The balancing account includes the expectation of higher net periodic benefit costs than costs recovered in rates in the near-term with lower net periodic benefit costs than costs recovered in rates expected in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest recognized when amounts are collected in rates. See Note 2 in the 2015 Form 10-K.

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	2016	2015	2016	2015
Beginning balance	$(6,968)	$(9,744)	$(7,162)	$(10,076)
Amounts reclassified from AOCL:				
Amortization of actuarial losses	269	548	590	1,096
Total reclassifications before tax	269	548	590	1,096
Tax (benefit) expense	(126)	(217)	(253)	(433)
Total reclassifications for the period	143	331	337	663
Ending balance	$(6,825)	$(9,413)	$(6,825)	$(9,413)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans
For the six months ended June 30, 2016, we made cash contributions totaling $6.1 million to our qualified defined benefit pension plan. We expect further plan contributions of $8.4 million during the remainder of 2016.

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Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Employer contributions totaled $2.5 million and $2.0 million for the six months ended June 30, 2016 and 2015, respectively.

See Note 8 in the 2015 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	2016	2015	2016	2015
Income taxes at statutory rates (federal and state)	$1,351	$1,429	$25,959	$20,321
Increase (decrease):				
Differences required to be flowed-through by regulatory commissions	65	85	1,583	1,414
Other, net	(34)	(100)	(774)	(1,238)
Total provision for income taxes	$1,382	$1,414	$26,768	$20,497
Effective tax rate	40.6 %	39.2 %	40.9 %	40.0 %

The effective tax rate for the three and six months ended June 30, 2016, compared to the same periods in 2015, increased primarily as a result of lower estimated depletion deductions from gas reserves activity in 2016. The effective tax rate for the three and six months ended June 30, 2015 benefited from the realization of deferred depletion benefits from 2013 and 2014. See Note 9 in the 2015 Form 10-K for more detail on income taxes and effective tax rates.

The 2015 tax year is subject to examination under the Internal Revenue Service (IRS) Compliance Assurance Process (CAP). Our 2016 tax year CAP application has been accepted by the IRS.

9. PROPERTY, PLANT, AND EQUIPMENT

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

	June 30,		December 31,
In thousands	2016	2015	2015
Utility plant in service	$2,783,883	$2,701,010	$2,745,485
Utility construction work in progress	57,068	38,024	39,288
Less: Accumulated depreciation	890,028	857,373	867,377
Utility plant, net	1,950,923	1,881,661	1,917,396
Non-utility plant in service	297,809	296,046	296,839

Non-utility construction work in progress	7,871	7,591	7,768
Less: Accumulated depreciation	42,151	36,349	39,340
Non-utility plant, net	263,529	267,288	265,267
Total property, plant, and equipment	$2,214,452	$2,148,949	$2,182,663
Capital expenditures in accrued liabilities	$11,345	$6,081	$8,985

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10. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of June 30, 2016. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the consolidated balance sheets. Our investment in gas reserves provides long-term price protection for utility customers and currently incorporates two agreements: the original agreement with Encana Oil & Gas (USA) Inc. under which we invested $178 million and the amended agreement with Jonah Energy LLC under which an additional $10 million was invested.

The cost of gas, including a carrying cost for the rate base investment made under the original agreement, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return.

Under the amended agreement we have the option to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, and may have the opportunity to participate in more wells in the future. Volumes produced from these wells are included in our Oregon PGA at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

The following table outlines our net gas reserves investment:

	June 30,		December 31,
In thousands	2016	2015	2015
Gas reserves, current	$15,707	$18,214	$17,094
Gas reserves, non-current	171,834	169,288	170,453
Less: Accumulated amortization	63,548	47,933	55,901
Total gas reserves[1]	123,993	139,569	131,646
Less: Deferred taxes on gas reserves	26,737	27,357	27,203
Net investment in gas reserves[1]	$97,256	$112,212	$104,443

(1) Our investment in additional wells included in total gas reserves was $7.3 million ($2.6 million net of deferred taxes), $8.8 million ($7.9 million net of deferred taxes) and $8.0 million ($4.3 million net of deferred taxes) at June 30, 2016 and 2015 and December 31, 2015, respectively.

Our investment is included on our consolidated balance sheets under gas reserves with our maximum loss exposure limited to our investment balance.

11. INVESTMENTS

Investments in Gas Pipeline
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.

Variable Interest Entity (VIE) Analysis
TWH is a VIE, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH's activities as we only have a 50% share of the entity and there are no stipulations

that allow us a disproportionate influence over it. Our investments in TWH and TWP are included in other investments on our consolidated balance sheets. 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, 2016 and 2015 and December 31, 2015. See Note 12 in the 2015 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 2015 Form 10-K.

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

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

Notional Amounts

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

	June 30,		December 31,
In thousands	2016	2015	2015
Natural gas (in therms):			
Financial	517,980	350,250	346,875
Physical	398,980	296,250	404,645
Foreign exchange	$7,254	$7,920	$ 9,025

Purchased Gas Adjustment (PGA)

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. Derivative contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon. In general, our commodity hedging for the current gas year is completed prior to the start of the upcoming gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. As of November 1, 2015, we reached our target hedge percentage of approximately 75% for the 2015-16 gas year. These hedge prices were included in the PGA filings and qualified for regulatory deferral.

Unrealized and Realized 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,			
	2016		2015	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$23,237	$ (87)	$10,020	$ 478
Operating revenues	29	—	(616)	—

Less:				
Amounts deferred to regulatory accounts on balance sheet	(23,271)	87	(9,618)	(478)
Total (loss) gain in pre-tax earnings	$(5)	$ —	$(214)	$ —

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In thousands	Six Months Ended June 30, 2016 Natural gas commodity	Foreign exchange	2015 Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$6,858	$ 154	$(13,461)	$ (263)
Operating revenues	29	—	22	—
Less:				
Amounts deferred to regulatory accounts on balance sheet	(6,892)	(154)	13,447	263
Total (loss) gain in pre-tax earnings	$(5)	$ —	$8	$ —

UNREALIZED GAIN/LOSS. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward 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 net losses of $7.6 million and $23.1 million for the three and six months ended June 30, 2016 and net losses of $7.9 million $22.0 million for the three and six months ended June 30, 2015, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments
No collateral was posted with or by our counterparties as of June 30, 2016 or 2015. 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 were not subject to collateral calls in 2016 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 upon current commodity financial swap and option contracts outstanding, which reflect unrealized gains of $4.9 million at June 30, 2016, 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:

In thousands	(Current Ratings) A+/A3	Credit Rating Downgrade Scenarios BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ —	$ —	$ —	$ —	$ 5,893
Without Adequate Assurance Calls	—	—	—	—	5,375

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our consolidated balance sheets. 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 derivative position would result in an asset of $8.1 million and a liability of $1.1 million as of June 30, 2016. As of June 30, 2015, our derivative position would have resulted in an asset of $1.1 million and a liability of $14.8 million. As of December 31, 2015, our derivative position would have resulted in an asset of $2.7 million and a liability of $25.5 million.

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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 2015 Form 10-K for additional information.

Fair Value

In accordance with fair value accounting, we include non-performance 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, 2016. As of June 30, 2016 and 2015, and December 31, 2015, the net fair value was an asset of $7.0 million, $13.7 million, and $22.8 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 quarters ended June 30, 2016 and 2015. See Note 2 in the 2015 Form 10-K.

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 (PRPs). When amounts are prudently expended related to site remediation, we have a recovery mechanism in place to collect 96.68% of remediation costs from Oregon customers, and we are allowed to defer environmental remediation costs allocated to customers in Washington annually until they are reviewed for prudence at a subsequent proceeding.

Our sites are subject to the remediation process prescribed by the Environmental Protection Agency (EPA) and the Oregon Department of Environmental Quality (ODEQ). The process begins with a remedial investigation (RI) to determine the nature and extent of contamination and then a risk assessment (RA) to establish whether the contamination at the site poses unacceptable risks to humans and the environment. Next, a feasibility study (FS) or an engineering evaluation/cost analysis (EE/CA) evaluates various remedial alternatives. It is at this point in the process when we are able to estimate a range of remediation costs and record a reasonable potential remediation liability, or make an adjustment to our existing liability. From this study, the regulatory agency selects a remedy and issues a Record of Decision (ROD). After the ROD is issued, we seek to negotiate a consent decree or consent judgment for designing and implementing the remedy. We have the ability to further refine estimates of remediation liabilities at that time.

Remediation may include treatment of contaminated media such as sediment, soil, and groundwater, removal and disposal of media, or institutional controls such as legal restrictions on future property use. Following construction of the remedy, the EPA and ODEQ also have requirements for ongoing maintenance, monitoring and other post-remediation care that may continue for many years. Where appropriate and reasonably known, we will provide for these costs in our remediation liabilities described above.

Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated where a range of potential loss is available. Unless there is an estimate within the 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 changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations, and the determination by regulators of remediation alternatives. In addition to remediation costs, we could also be subject to Natural Resource Damages (NRD) claims. We will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. As of June 30, 2016, we have not received any material NRD claims.

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Environmental Sites

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities on the consolidated balance sheets:

	Current Liabilities			Non-Current Liabilities		
	June 30,		December 31,	June 30,		December 31,
In thousands	2016	2015	2015	2016	2015	2015
Portland Harbor site:						
Gasco/Siltronic Sediments	$1,777	$1,512	$ 2,229	$42,991	$38,342	$42,641
Other Portland Harbor	1,580	1,208	1,972	4,541	4,941	5,073
Gasco Upland site	9,033	5,938	10,599	51,081	37,031	52,117
Siltronic Upland site	—	710	951	352	390	337
Central Service Center site	112	153	25	—	—	—
Front Street site	984	665	1,155	7,739	107	7,748
Oregon Steel Mills	—	—	—	179	179	179
Total	$13,486	$10,186	$ 16,931	$106,883	$80,990	$108,095

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands and the Siltronic uplands sites. We are a PRP to the Superfund site and have joined with some of the other PRPs (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/Feasibility Study (RI/FS), which we submitted to the EPA in 2012. In August 2015, the EPA issued its own Draft Feasibility Study (Draft FS) for comment. The EPA Draft FS provides a new range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of present value costs estimated by the EPA for various remedial alternatives for the entire Portland Harbor, as provided by the EPA's Draft FS, is $791 million to $2.45 billion. The range provided in the EPA's Draft FS is based on cost alternatives the EPA estimates to have an accuracy between -30% and +50% of actual costs, depending on the scope of work.

In June 2016, the EPA issued their Final Feasibility Study (Final FS) and proposed remediation plan (Proposed Plan) for the Portland Harbor Superfund site. The Proposed Plan presents the EPA’s preferred clean-up alternative, which estimates the present value cost at approximately $746 million with an accuracy between -30% and +50% of actual costs, a significant reduction from prior estimates for this level of cleanup. Along with several members of the LWG, we have filed a dispute with the EPA over concerns that the EPA's Final FS contains factual and technical errors and is insufficient to support remedy selection. The EPA has stated it intends to release a Record of Decision, the final determination of a cleanup approach for the Portland Harbor site, by the end of 2016.

While the EPA's Final FS and Proposed Plan provides a higher range of costs than the LWG's submission in 2012, our potential liability is still a portion of the costs of the remedy for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 PRPs. We are participating in a non-binding allocation process in an effort to settle this potential liability. The Final FS and Proposed Plan do not provide any additional clarification around allocation of costs.

We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. We submitted a draft 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 $44.8 million to $350 million. We have recorded a liability of $44.8 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

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Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG. 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 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 recorded 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 or noted above.

GASCO UPLANDS SITE. A predecessor of NW Natural owned 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 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.

We submitted a revised Remedial Investigation Report for the uplands to ODEQ in May 2007. In March 2015, ODEQ approved the RA NW Natural submitted in 2010, enabling us to begin work on the FS in 2016. 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.

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 initial 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 is highly dependent on 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 $19.0 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. A portion of these proceeds was non-cash in 2014.

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 remediation and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated at this time.

Siltronic Upland. A portion of the Siltronic property adjacent to the Gasco site was formerly owned by Portland Gas and Coke, NW Natural's predecessor. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for ODEQ.

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

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated (the former Portland Gas Manufacturing site, or PGM). At ODEQ's request, we conducted a sediment and source control investigation and provided findings to ODEQ. In December 2015, we completed a FS on the former Portland Gas Manufacturing site. The FS provided a range of $7.6 million to $12.9 million for remedial costs. We have recorded a liability at the low end of the range of possible loss as no alternative in the range is considered more likely than another. Further, we have recognized an additional liability of $1.1 million for additional studies and design costs as well as regulatory oversight throughout the clean-up that will be required to assist in ODEQ making a remedy selection and completing a design.

Oregon Steel Mills site. Refer to the "Legal Proceedings," below.

Site Remediation and Recovery Mechanism (SRRM)
We have a SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test.

REGULATORY ACTIVITIES. In February 2015, the OPUC issued an Order addressing outstanding issues related to the SRRM (2015 Order), which required us to forego collection of $15 million out of approximately $95 million in total environmental remediation expenses and associated carrying costs the Company had deferred through 2012 based on the OPUC's determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. As a result, we recognized a $15.0 million non-cash charge in operations and maintenance expense in the first quarter of 2015. Also, as a result of the 2015 Order, we recognized $5.3 million pre-tax of interest income related to the equity earnings on our deferred environmental expenses.

In addition, the OPUC issued a subsequent Order regarding SRRM implementation (2016 Order) in January 2016 in which the OPUC: (1) disallowed the recovery of $2.8 million of interest earned on the previously disallowed environmental expenditure amounts; (2) clarified the state allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) confirmed our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders. As a result of the 2016 Order, we recognized a $3.3 million non-cash charge in the first quarter, of which $2.8 million is reflected in other income and expense, net and $0.5 million is included in operations and maintenance expense.
COLLECTIONS FROM OREGON CUSTOMERS. The SRRM provides us with the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test. The SRRM created three classes of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. The Company anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the end of the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. We included $8.4 million of deferred remediation expense approved by the OPUC for collection during the 2015-2016 PGA year.

In addition to the collection amount noted above, the Order also provides for the annual collection of $5 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize our deferred regulatory asset balance through operating expense.

We received total environmental insurance proceeds of approximately $150 million as a result of settlements from our litigation that was dismissed in July 2014. Under the OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012, and the remaining two-thirds will be applied to costs over the next 20 years. Annually, the Order provided for the application of $5 million of insurance proceeds plus interest against deferred remediation expense deemed prudent in the same annual period; annual amounts not utilized are carried forward to apply against future prudently incurred costs. We accrue interest on the insurance proceeds in the customer's favor at a rate equal to the five-year treasury rate plus 100 basis points. As of June 30, 2016, we have applied $63.2 million of insurance proceeds to prudently incurred remediation costs.

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The following table presents information regarding the total regulatory asset deferred:

	June 30,		December 31,
In thousands	2016	2015	2015
Deferred costs and interest[1]	$53,065	$79,135	$79,505
Accrued site liabilities[2]	120,075	91,176	125,026
Insurance proceeds and interest	(97,547)	(120,394)	(118,677)
Total regulatory asset deferral[1]	75,593	49,917	85,854
Current regulatory assets[3]	9,610	—	9,270
Long-term regulatory assets	65,983	49,917	76,584

(1) Includes pre-review and post-review deferred costs, amounts currently in amortization, and interest, net of amounts collected from customers.

(2) Excludes $0.3 million, or 3.32% of the Front Street site liability as the OPUC allows recovery of 96.68% of costs for all sites, including those that historically served only Oregon customers.

(3) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and 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. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the $5 million tariff rider. The amounts allocable to Oregon are recoverable through utility rates, subject to an earnings test.

ENVIRONMENTAL EARNINGS TEST. The 2015 Order directed us to implement an annual environmental earnings test for our prudently incurred remediation expense. Prudently incurred Oregon allocated annual remediation expense and interest in excess of the $5 million tariff rider and $5 million insurance proceeds application plus interest on the insurance proceeds are recoverable through the SRRM, to the extent the utility earns at or below our authorized Return On Equity (ROE). To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than $10 million (plus interest from insurance proceeds) with those earnings that exceed its authorized ROE.

Under the 2015 Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds three years from the original Order, or earlier if the Company gains greater certainty about its future remediation costs, to consider whether adjustments to the mechanism may be appropriate.

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

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, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows. 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 Evraz 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

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predicted with certainty, we do not expect the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

For additional information regarding other commitments and contingencies, see Note 14 in the 2015 Form 10-K.

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 discussion refers to our consolidated results for the three and six months ended June 30, 2016 and 2015. References in this discussion 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 month periods are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2015 Annual Report on Form 10-K (2015 Form 10-K).

The consolidated financial statements include NW Natural and its direct and indirect wholly-owned subsidiaries including:

- 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).

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, and asset management services. Other includes NWN Energy's equity investment in Trail West Holding, LLC (TWH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Trail West Pipeline, LLC (TWP), and NNG Financial's equity investment in Kelso-Beaver Pipeline (KB Pipeline). For a further discussion of our business segments and other, see Note 4.

In addition to presenting the results of operations and earnings amounts in total, certain financial measures are expressed in cents per share or exclude the after-tax regulatory disallowance related to the OPUC's 2015 and 2016 environmental orders, which are non-GAAP financial measures. We present net income and earnings per share (EPS) excluding the regulatory disallowances 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 disallowances make period to period comparisons of operations difficult or potentially confusing. Financial measures are expressed in cents per share as these amounts reflect factors that directly impact earnings, including income taxes. All references in this section to EPS are on the basis of diluted shares (see Note 3). We use such non-GAAP financial 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.

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EXECUTIVE SUMMARY

We manage our business and strategic initiatives with a long-term view of providing natural gas service safely and reliably to customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See "2016 Outlook" in our 2015 Form 10-K for more information. Highlights for the quarter include:

- added over 10,500 customers during the past twelve months for a growth rate of 1.5% at June 30, 2016.
- received one of the final permits from the Energy Facility Siting Council for our North Mist gas storage expansion project in April of 2016 and we are now finalizing a few additional permits, completing the final cost estimate, and anticipate the notice to proceed in the fall of 2016 with expectations of a winter of 2018-2019 in-service date.
- utility customer bill credits totaling nearly $30 million were issued in June of 2016 related to lower than projected wholesale natural gas prices realized and our asset management activities.

Key financial highlights include:

	Three Months Ended June 30,				
	2016		2015		
In millions, except per share data	Amount	Per Share	Amount	Per Share	$ Change
Consolidated net income	$2,019	$0.07	$2,197	$0.08	$(178)
Utility margin	69,371		70,715		(1,344)
Gas storage operating revenues	6,992		5,333		1,659

THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Consolidated net income decreased $0.2 million primarily due to the following factors:

- a decrease in utility margin of $1.3 million primarily due to lower customer usage from significantly warmer weather than the prior year, partially offset by customer growth; and
- an increase of $0.7 million in operating and maintenance expenses; partially offset by
- an increase in gas storage revenues of $1.7 million largely due to higher revenues from our asset management agreements and higher contract prices at our Gill Ranch facility for the 2016-2017 gas year.

	Six Months Ended June 30,				
	2016		2015		
In millions, except per share data	Amount	Per Share	Amount	Per Share	$ Change
Consolidated net income	$38,660	$1.40	$30,683	$1.12	$7,977
Adjustments:					
Regulatory environmental disallowance, net of taxes ($1,304 and $5,925)(1)	1,996	0.07	9,075	0.33	(7,079)
Adjusted consolidated net income(1)	$40,656	$1.47	$39,758	$1.45	$898
Utility margin	$206,035		$201,316		$4,719
Gas storage operating revenues	12,361		10,636		1,725

(1) Regulatory environmental disallowance of $3.3 million in 2016 is recorded in utility other income and expense, net ($2.8 million) and utility operations and maintenance expense ($0.5 million). Regulatory environmental disallowance of $15.0 million in 2015 is recorded in utility operations and maintenance expense. Adjusted EPS and net income are non-GAAP financial measures based on the after-tax disallowance. EPS is calculated using the combined federal and state statutory tax rate of 39.5% and 27.6 million and 27.4 million diluted shares for the six months ended June 30, 2016 and 2015, respectively.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Consolidated net income increased $8.0 million during the six months ended June 30, 2016 primarily due to the environmental disallowance described in the table above. Excluding the impact of the regulatory environmental orders in 2015 and 2016, net income increased $0.9 million primarily due to the following factors:

- a $4.7 million increase in utility margin primarily due to customer growth and gains from gas cost incentive sharing;
- an increase of $1.7 million in gas storage revenues largely due to higher revenues from our asset management agreements and higher contract values at our Gill Ranch facility for the 2016-2017 gas year; partially offset by

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- a $5.2 million decrease in other income and expense, net related to the recognition of $5.3 million of equity earnings on deferred regulatory asset balances as a result of the OPUC SRRM Order in the first quarter of 2015.

Dividends

Dividend highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
Per common share	2016	2015	2016	2015	QTR Change	YTD Change
Dividends paid	$0.4675	$0.4650	$0.9350	$0.9300	$0.0025	$0.0050

The Board of Directors declared a quarterly dividend on our common stock of $0.4675 per share, payable on August 15, 2016, to shareholders of record on July 29, 2016, reflecting an indicated annual dividend rate of $1.87 per share.

RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, WUTC, and 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. Approximately 89% of our utility gas volumes and revenues were 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 proceedings in Oregon and Washington. They 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 Proceeding Updates" below.

GAS STORAGE. Our gas storage business is subject to regulation by the OPUC, WUTC, 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, and regulate intrastate storage services. The FERC regulates interstate storage services. The FERC uses 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 last regulatory filing. The OPUC Schedule 80 rates are tied to the FERC rates, and are updated whenever we modify our FERC maximum rates. 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 2015, approximately 72% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 28% from California operations.

Most Recent General Rate Cases

OREGON. Effective November 1, 2012, the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt.

WASHINGTON. Effective January 1, 2009, the WUTC authorized rates to customers based on an ROE of 10.1% and an overall rate of return of 8.4% with a capital structure of 51% common equity, 5% short-term debt, and 44% long-term debt.

FERC. We are required under our Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. In December 2013 we filed a rate petition, which was approved in 2014 and allows for the maximum cost-based rates for our interstate gas storage services. These rates were effective January 1, 2014, with the rate changes having no significant impact on our revenues.

Regulatory Proceeding Updates

During the three and six months ended June 30, 2016, we were involved in the regulatory activities discussed below.

ENVIRONMENTAL COST DEFERRAL AND SITE REMEDIATION AND RECOVERY MECHANISM (SRRM). In February 2015, as part of the implementation of the SRRM, the OPUC issued an Order (2015 Order) requiring us to forego collection of $15 million out of approximately $95 million in total environmental remediation expenses and associated carrying costs we had deferred through 2012 based on the OPUC's determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. As a result, we recognized a $15.0 million non-cash charge in operations and maintenance expense in the first quarter of 2015. Also, as a result of the 2015 Order, we recognized $5.3 million pre-tax of interest income related to the equity earnings on our deferred environmental expenses in the first quarter of 2015.

In addition, the OPUC issued a subsequent Order regarding our SRRM (2016 Order) in January 2016 in which the OPUC: (1) disallowed the recovery of $2.8 million of interest earned on the previously disallowed environmental expenditure amounts; (2) clarified the state allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) confirmed our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders. As a result of the 2016 Order, we recognized a $3.3 million non-cash charge, of which $2.8 million is reflected in other income and expense, net and $0.5 million is included in operations and maintenance expense. Our compliance filing related to the 2016 Order was filed with the OPUC on March 11, 2016. We do not expect any further action by the OPUC related to that filing. See Note 13 regarding our SRRM.

SYSTEM INTEGRITY PROGRAM (SIP). We filed a request to extend the SIP program in the fourth quarter of 2014. The OPUC considered our renewal request at a public meeting in March 2015 and suspended our filing and ordered additional process, including involvement of other gas utilities in the state, before making a final decision. In 2016, we withdrew our request to extend the SIP program and remain focused on establishing guidelines for future safety cost trackers with the OPUC.

HEDGING. In our 2014 Integrated Resource Plan, we proposed to the OPUC that we engage in continued long-term gas hedging. The OPUC is considering long-term hedging along with a general review of overall hedging practices among all gas utilities in the state. The OPUC therefore opened a new docket to discuss broader gas hedging practices across gas utilities in Oregon. Our request for the OPUC to consider long-term hedging practices will be considered as part of this docket. The OPUC established that this docket will follow two phases. The first phase was focused on an analytical review of hedging and hedging practices. We are currently working through the second phase regarding potential hedging guidelines. After the second phase is complete, a status report will be submitted to the OPUC, and the remainder of the process will be determined at that time.

The Washington Utilities and Transportation Commission (WUTC) also is conducting an investigation into the hedging practices of gas utilities operating in Washington, and considering whether it should require gas utilities to implement certain practices related to hedging. The WUTC is reviewing comments received from all parties and will determine next steps in the docket after reviewing those comments.

INTERSTATE STORAGE AND OPTIMIZATION 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. We are continuing to engage with the parties, as directed by the OPUC, to hire a third party and facilitate completion of the work directed by the OPUC.

CARBON SOLUTIONS PROGRAM. Oregon Senate Bill 844 (SB 844) required the OPUC to develop rules and programs to reduce carbon emissions in Oregon. In June 2015, we submitted our first project related to Combined Heat and Power (CHP) for OPUC approval. The submitted CHP program would pay owners of new commercial- and industrial-scale CHP systems for verified carbon emission reductions. In April 2016, the OPUC issued an order declining our program as submitted and provided guidance on program structure for potential future submissions. We are currently contemplating our next steps for this program.

WEATHER NORMALIZATION MECHANISM (WARM). In Oregon, WARM is applied to residential and commercial customers' bills to adjust for temperature variances from average weather. In 2015, the OPUC initiated a review of the WARM mechanism as a result of customer complaints received related to surcharges applied under the WARM mechanism due to the record warm weather in our service territory during the 2014-15 winter. In May of 2016, we filed a stipulation among the parties resolving the issues identified in the review. In June 2016, the OPUC issued an order adopting the stipulation, which included modest changes to the WARM mechanism. The most notable change relates to the timing of collection of any unbilled WARM amounts, due to operation of certain caps on monthly bills in the program. Previously, any unbilled WARM amounts deferred throughout the WARM period were

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billed to customers in June. Under the adjusted WARM mechanism, the collections of any unbilled WARM amounts will continue to be deferred and will earn a carry charge until collected in the PGA the following year. These changes do not reduce the value WARM provides to us or our customers in mitigating the impact from variations in weather.

Rate Mechanisms

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

Each year, 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 2015-16 gas year (November 1, 2015 - October 31, 2016) hedged at 75% of our forecasted sales volumes, including 44% in financial swap and option contracts and 31% in physical gas supplies.

In addition to the amount hedged for the current gas contract year, we are also hedged in future years at approximately 62% for the 2016-17 gas year and between 4% and 23% for annual requirements over the following five gas years as of June 30, 2016. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather, economic conditions, and estimated gas reserve production. Also, our storage inventory levels may increase or decrease with storage expansion, changes in storage contracts with third parties, and/or storage recall by the utility.

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

EARNINGS TEST REVIEW. We are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred or refunded to customers. Under this provision, if we select the 80% deferral gas cost option, 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 2014-15 PGA year, and we selected the 80% deferral option for the 2015-16 PGA year. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For the 2015 calendar year, the ROE threshold was 10.60%. We filed our 2015 earnings test in April of 2016 and it was approved by the Commission in July 2016. As a result, we were not subject to a customer refund adjustment for 2015.

GAS RESERVES. The cost of gas, including a carrying cost for the rate base investment made under the original agreement, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return.

In March 2014, we amended the original gas reserves agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field. We also retained the right to invest in new wells with Jonah Energy. Under the amended agreement we have the option to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, and may have the opportunity to participate in more wells in the future. Volumes produced from these wells are included in our Oregon PGA at a fixed rate of $0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment. See Note 10.

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DECOUPLING. In Oregon, we have a decoupling mechanism. Decoupling is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers’ efforts to conserve energy. The Oregon decoupling mechanism was reauthorized and the baseline expected usage per customer was set in the 2012 Oregon general rate case. This mechanism employs a use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes. The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the annual PGA filing. In Washington, customer use is not covered by such a tariff. See "Business Segments—Local Gas Distribution Utility Operations" below.

WEATHER NORMALIZATION TARIFF. In Oregon, we have an approved weather normalization mechanism, which is applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills from December through May of each heating season. The mechanism adjusts the margin component of customers’ rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. This weather normalization mechanism was reauthorized in the 2012 Oregon general rate case without an expiration date. Residential and commercial customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of June 30, 2016, 9% of total customers had opted out. We do not have a weather normalization mechanism approved for residential and commercial Washington customers, which account for about 11% of total customers. See "Business Segments—Local Gas Distribution Utility Operations" below.

INDUSTRIAL TARIFFS. The OPUC and WUTC have approved tariffs covering utility service to our major industrial customers, including terms, which are intended to give us certainty in the level of gas supplies we need to acquire to serve this customer group. The terms include, among other things, an annual election period, special pricing provisions for out-of-cycle changes, and a requirement that industrial customers complete the term of their service election under our annual PGA tariff.

ENVIRONMENTAL COST DEFERRAL AND SRRM. In Oregon, we have a SRRM through which we track and have the ability to recover prudently incurred past deferred and future environmental remediation costs allocable to Oregon, subject to an earnings test.

The SRRM defines three classes of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. We anticipate the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. We included $8.4 million of deferred remediation expense approved by the OPUC for collection during the 2015-2016 PGA year.

The SRRM earnings test is an annual review of our adjusted utility ROE compared to our authorized utility ROE, which is currently 9.5%. To apply the earnings test first we must determine what, if any, costs are subject to the test through the following calculation:

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Annual spend
Less: $5 million tariff rider(1)
Prior year carry-over(2)
$5 million insurance + interest on insurance
Total deferred annual spend subject to earnings test
Less: over-earnings adjustment, if any
Add: deferred interest on annual spend(3)
Total amount transferred to post-review

(1) Tariff rider went into Oregon customer rates beginning November 1, 2015.
(2) Prior year carry-over results when the prior year amount transferred to post-review is negative. The negative amount is carried over to offset annual spend in the following year.
(3) Deferred interest is added to annual spend to the extent the spend is recoverable.

If the adjusted utility ROE is greater than the authorized utility ROE, then we could be required to expense up to the amount that results in the utility earning its authorized ROE. For 2015, we have performed this test, which was submitted to the OPUC in April 2016, and have concluded there was no earnings test adjustment for 2015.

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

PENSION COST DEFERRAL AND PENSION BALANCING ACCOUNT. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return, which is currently 7.78%. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and our pension contributions. Pension expense deferrals, including interest, were $3.2 million and $4.3 million as of June 30, 2016 and 2015, respectively.

GAS STORAGE SHARING AND COST OF GAS CUSTOMER CREDITS. In the second quarter of 2016, we received regulatory approval to provide an interstate storage credit of $9.4 million to its Oregon utility customers, which was reflected in their June bills. These credits are part of our regulatory incentive sharing mechanism related to non-utility Mist storage and asset management service. The OPUC approved a $9.6 million interstate storage credit to Oregon customers in June 2015. The Washington portion of these credits will be included in the Washington PGA.

During May 2016, we filed requests with the OPUC and WUTC to credit customers their portion of the gas cost sharing incentive for the 2015-2016 gas year in June rather than through the 2016-2017 PGA; the credit totaled $19.4 million and resulted from lower than projected gas costs driven by warmer weather, lower volume usage, and lower market prices. During the second quarter of 2016, the OPUC and WUTC approved our requests and amounts were credited to customers in June 2016.

For a discussion of other rate mechanisms, see Part II, Item 7, "Results of Operations—Regulatory Matters—"Rate Mechanisms" in our 2015 Form 10-K.

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 "Regulatory Matters—Rate Mechanisms" above.

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Utility segment highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
Dollars and therms in thousands, except EPS data	2016	2015	2016	2015	QTR Change	YTD Change
Utility net income	$507	$2,245	$36,359	$30,580	$(1,738)	$5,779
EPS - utility segment	0.02	0.08	1.32	1.12	(0.06)	0.20
Gas sold and delivered (in therms)	192,933	207,886	565,482	537,863	(14,953)	27,619
Utility margin[(1)]	$69,371	$70,715	$206,035	$201,316	$(1,344)	$4,719

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

THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. The primary factors contributing to the $1.7 million or $0.06 per share decrease in utility net income were as follows:

- a $1.3 million decrease in utility margin primarily due to:
  - a decrease of approximately $2.0 million due to lower customer usage from significantly warmer weather than in the prior year, 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; partially offset by
  - a $0.7 million increase from customer growth and added loads under higher commercial rate schedules
- a $0.7 million decrease in other income and expense, net primarily due to lower interest earned on net regulatory assets; and
- a $0.9 million increase in operations and maintenance expense primarily due to professional services costs and contract work.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. The primary factors contributing to the $5.8 million or $0.20 per share increase in utility net income were as follows:

- a $4.7 million increase in utility margin primarily due to:
  - a $2.9 million increase from customer growth and added loads under higher commercial rate schedules;
  - a $2.5 million increase from gains in gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA; and
  - a $1.0 million increase from added rate-base returns on certain investments; partially offset by
  - a decrease of approximately $1.0 million due to lower customer usage from significantly warmer weather during the second quarter of 2016 than in the prior year, 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.
- a $13.8 million decrease in operations and maintenance expense primarily due to the $15.0 million regulatory disallowance charge taken in the prior year; partially offset by
- an $8.5 million decrease in other income and expense, net primarily due to a $2.8 million interest write-off as a result of the 2016 Order from the OPUC in the first quarter of 2016 and the recognition of $5.3 million of equity earnings on deferred regulatory asset balances in February 2015.

Total utility volumes sold and delivered in the three months ended June 30, 2016 decreased 7% over the same period in 2015 primarily due to the impact of 21% warmer weather. Although weather for the six months ended June 30, 2016 was comparable to the prior year, deliveries increased 5% due to comparatively colder weather in the first quarter of 2016 during our peak heating season. Weather was 22% warmer than average over the first six months of 2016 due to significantly warmer weather in the second quarter of 2016.

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

	Three Months Ended June 30,		Six Months Ended June 30,		Favorable/(Unfavorable)	
In thousands, except degree day and customer data	2016	2015	2016	2015	QTR Change	YTD Change
Utility volumes (therms):						
Residential and commercial sales	82,625	97,066	325,499	303,883	(14,441)	21,616
Industrial sales and transportation	110,308	110,820	239,983	233,980	(512)	6,003
Total utility volumes sold and delivered	192,933	207,886	565,482	537,863	(14,953)	27,619
Utility operating revenues:						
Residential and commercial sales	$82,509	$117,919	$320,181	$358,831	$(35,410)	$(38,650)
Industrial sales and transportation	10,972	17,138	28,636	37,664	(6,166)	(9,028)
Other revenues	1,102	1,131	2,513	2,537	(29)	(24)
Less: Revenue taxes	2,448	3,297	9,091	9,835	(849)	(744)
Total utility operating revenues	92,135	132,891	342,239	389,197	(40,756)	(46,958)
Less: Cost of gas	20,871	62,176	129,282	187,881	41,305	58,599
Less: Environmental remediation expense	1,893	—	6,922	—	(1,893)	(6,922)
Utility margin	$69,371	$70,715	$206,035	$201,316	$(1,344)	$4,719
Utility margin:[1]						
Residential and commercial sales	$60,888	$61,940	$184,372	$182,312	$(1,052)	$2,060
Industrial sales and transportation	7,084	7,258	15,285	14,832	(174)	453
Miscellaneous revenues	1,097	1,133	2,503	2,539	(36)	(36)
Gain from gas cost incentive sharing	412	340	4,066	1,561	72	2,505
Other margin adjustments	(110)	44	(191)	72	(154)	(263)
Utility margin	$69,371	$70,715	$206,035	$201,316	$(1,344)	$4,719
Degree days						
Average[2]	691	691	2,562	2,546	—	16
Actual	403	512	1,988	1,993	(21)%	—%
Percent warmer than average weather[2]	(42)%	(26)%	(22)%	(22)%		

	As of June 30,			
Customers - end of period:	2016	2015	Change	% Change
Residential customers	650,584	640,581	10,003	1.6%
Commercial customers	66,604	66,036	568	0.9%
Industrial customers	1,003	922	81	8.8%
Total number of customers	718,191	707,539	10,652	1.5%

(1) Amounts reported as margin for each category of customers are operating revenues, which are net of revenue taxes, less cost of gas and environmental remediation expense.

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

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Residential and Commercial Sales

Residential and commercial sales highlights include:

In thousands	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	QTR Change	YTD Change
Volumes (therms):						
Residential sales	47,069	56,655	202,301	186,715	(9,586)	15,586
Commercial sales	35,556	40,411	123,198	117,168	(4,855)	6,030
Total volumes	82,625	97,066	325,499	303,883	(14,441)	21,616
Operating revenues:						
Residential sales	$53,599	$75,775	$214,299	$236,312	$(22,176)	$(22,013)
Commercial sales	28,910	42,144	105,882	122,519	(13,234)	(16,637)
Total operating revenues	$82,509	$117,919	$320,181	$358,831	$(35,410)	$(38,650)
Utility margin:						
Residential:						
Sales	$35,429	$39,764	$117,090	$110,540	$(4,335)	$6,550
Weather normalization	4,735	139	13,966	12,492	4,596	1,474
Decoupling	1,776	2,964	(2,159)	4,169	(1,188)	(6,328)
Total residential utility margin	41,940	42,867	128,897	127,201	(927)	1,696
Commercial:						
Sales	14,993	16,506	45,898	44,261	(1,513)	1,637
Weather normalization	1,737	(29)	5,483	5,215	1,766	268
Decoupling	2,218	2,596	4,094	5,635	(378)	(1,541)
Total commercial utility margin	18,948	19,073	55,475	55,111	(125)	364
Total utility margin	$60,888	$61,940	$184,372	$182,312	$(1,052)	$2,060

THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes decreased 14.4 million therms, or 15%, primarily reflecting 21% warmer weather;
- operating revenues decreased $35.4 million due to a 60% decrease in average cost of gas over last year and a 15% decrease in sales volumes; and
- utility margin decreased $1.1 million primarily due to the effects of warmer weather, partially offset by increases from commercial and residential customer growth.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 21.6 million therms, or 7%, primarily due to colder weather in the first quarter of 2016 compared to record warm weather in 2015 and customer growth;
- operating revenues decreased $38.7 million due to a 35% decrease in average cost of gas over last year partially offset by a 7% increase in sales volumes; and
- utility margin increased $2.1 million due to both residential and commercial customer growth 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 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 on November 1, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

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Industrial sales and transportation highlights include:

In thousands	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015	QTR Change	YTD Change
Volumes (therms):						
Industrial - firm sales	7,122	7,305	16,546	15,956	(183)	590
Industrial - firm transportation	35,518	34,796	79,719	75,624	722	4,095
Industrial - interruptible sales	11,322	20,853	26,372	37,245	(9,531)	(10,873)
Industrial - interruptible transportation	56,346	47,866	117,346	105,155	8,480	12,191
Total volumes	110,308	110,820	239,983	233,980	(512)	6,003
Utility margin:						
Industrial - firm and interruptible sales	$2,613	$3,165	$5,776	$6,382	(552)	(606)
Industrial - firm and interruptible transportation	4,471	4,093	9,509	8,450	378	1,059
Industrial - sales and transportation	$7,084	$7,258	$15,285	$14,832	$(174)	$453

THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Industrial sales and transportation volumes decreased by 0.5 million therms and utility margin decreased $0.2 million due to warmer weather and lower usage from customers with heating load.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Industrial sales and transportation volumes increased by 6.0 million therms and utility margin increased $0.5 million due to annual customer service election changes.

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 earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism which has been described under "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" above. In addition to the PGA incentive sharing mechanism, gains and losses from hedge contracts entered into after annual PGA rates are effective for Oregon customers are also required to be shared and therefore may impact net income. Further, we also have a regulatory agreement whereby we earn a rate of return on our investment in the gas reserves acquired under the original agreement with Encana and include gas from our amended gas reserves agreement at a fixed rate of $0.4725 per therm, which are also reflected in utility margin. See "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities" in our 2015 Form 10-K.

Cost of gas highlights include:

Dollars and therms in thousands	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015	QTR Change	YTD Change
Cost of gas	$20,871	$62,176	$129,282	$187,881	$(41,305)	$(58,599)
Volumes sold (therms)(1)	101,069	118,633	368,417	350,493	(17,564)	17,924
Average cost of gas (cents per therm)	$0.21	$0.52	$0.35	$0.54	$(0.31)	$(0.19)
Gain from gas cost incentive sharing(2)	412	340	4,066	1,561	72	2,505

(1) This calculation excludes volumes delivered to transportation only customers.
(2) For a discussion of our gas cost incentive sharing mechanism, see “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above.

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THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Cost of gas decreased $41.3 million, or 66%, primarily due to a 60% decrease in average cost of gas reflecting the $19.4 million refund to customers, lower market prices for natural gas, and a 15% decrease in volumes from comparatively warmer weather.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Cost of gas decreased $58.6 million, or 31%, primarily due to a 35% decrease in average cost of gas reflecting the $19.4 million refund to customers and lower market prices for natural gas, partially offset by a 5% increase in volumes mainly from comparatively colder weather in the first quarter of 2016.

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

Gas storage segment highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
In thousands, except EPS data	2016	2015	2016	2015	QTR Change	YTD Change
Gas storage net income (loss)	$1,439	$(86)	$2,175	$ 28	$1,525	$2,147
EPS - gas storage segment	0.05	—	0.08	—	0.05	0.08
Operating revenues	6,992	5,333	12,361	10,636	1,659	1,725
Operating expenses	4,112	4,594	7,756	8,842	(482)	(1,086)

THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Our gas storage segment net income increased $1.5 million primarily due to a $1.7 million increase in revenue from asset management agreements and higher contract prices at our Gill Ranch facility for the 2016-2017 gas year. Further, operating expenses decreased $0.5 million from lower operations and maintenance costs, and interest expense decreased $0.4 million from the retirement of $20 million of Gill Ranch's debt in December of 2015.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Our gas storage segment net income increased $2.1 million primarily due to a $1.7 million increase in revenue from asset management agreements and higher contract prices at our Gill Ranch facility for the 2016-2017 gas year. Further, operating expenses decreased $1.1 million from lower power costs at our Gill Ranch facility and lower general and administrative expenses, and interest expense decreased $0.7 million from the early retirement of $20 million of Gill Ranch's debt in December of 2015.

Our Mist gas storage facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location. 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 have completed our contracting for the 2016-17 gas storage year and have seen a slight improvement in pricing compared to the 2015-16 gas storage year.

For our Gill Ranch facility, prices for the 2015-16 and 2016-17 gas years have shown slight improvement, and may continue to show improvement in future years, however they remain low relative to the pricing in our original long-term contracts, which ended primarily in the 2013-14 gas storage year. In the future, we may also see 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 emission 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 storage market conditions in and around California. These factors, if they occur, may contribute to higher summer/winter natural gas price spreads, gas price volatility, and gas storage values. We are continuing to explore opportunities to increase revenues by identifying higher value

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customers to provide with enhanced services and also by capitalizing on opportunities that fit our business-risk profile.

In addition, in October 2015 a significant natural gas leak occurred at a southern California gas storage facility that persisted in early 2016. At this time, we do not know the long-term effects of this incident on gas storage prices. Regulatory and legislative proceedings at both the national and California state level have been opened in response to the incident, and it is likely additional regulations and legislation will result in higher costs for all storage providers. The proposed regulation and legislation have created uncertainty around the future market value of storage in California. The potential costs of complying with the proposed regulation and legislation could include one-time capital expenditures and/or ongoing operations and maintenance costs. As a result of the proposed regulation and legislation, the nature of future storage contracts and market values could be impacted.

If we are unsuccessful in identifying new higher value customers, future storage values do not improve, and/or new regulation and legislation require significant capital and on-going spending to maintain the facility, this could have a negative impact on our future cash flows and could result in impairment of our Gill Ranch gas storage facility, which had a net book value of $198.3 million at June 30, 2016. Refer to Note 2 in our 2015 Form 10-K for more information regarding our accounting policy for impairment of long-lived assets.

Other

Other primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in TWH, which has invested in the Trail West pipeline project, and other miscellaneous non-utility investments and business activities. There were no significant changes in our other activities during the three and six months ended June 30, 2016. See Note 4 and Note 11 for further details on other activities and our investment in TWH.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
In thousands	2016	2015	2016	2015	QTR Change	YTD Change
Operations and maintenance	$35,962	$35,311	$74,901	$89,427	$ 651	$(14,526)

THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Operations and maintenance expense increased $0.7 million, primarily due to the following factors:

- a $1.5 million increase in non-payroll costs primarily due to professional service costs and contractor work; partially offset by
- a $0.8 million decrease in utility payroll and benefits primarily due to reduced incentive compensation and retirement expense.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Operations and maintenance expense decreased $14.5 million, primarily due to the following factors:

- the $15 million pre-tax charge for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals recorded in 2015. We also expensed an additional $1 million related to the 2015 Order;
- a $0.6 million decrease in gas storage operating expenses from lower general, administrative, and power costs at our Gill Ranch facility;
- a $0.5 million decrease in payroll and benefits due to lower retirement plan expenses; partially offset by
- a $2.1 million increase in non-payroll costs primarily due to contractor work and professional services costs; and

- a $0.5 million pre-tax charge related to the reserve for the state allocation of environmental sites based on the 2016 Order.

Delinquent customer receivable balances continue to remain at historically low levels. The utility's annualized bad debt expense as a percent of revenues was 0.1% for the six months ended June 30, 2016 and has remained well below 0.5% of revenues since 2007.

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Other Income and (Expense), Net

Other income and (expense), net highlights include:

In thousands	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015	QTR Change	YTD Change
Other income and (expense), net	$513	$1,135	$(1,796)	$6,184	$(622)	$(7,980)

THREE MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Other income and expense, net decreased $0.6 million primarily due to lower interest earned on net regulatory assets.

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Other income and expense, net decreased $8.0 million primarily due to the recognition of $5.3 million of the equity component in interest income from our deferred environmental expenses in the prior year, which did not recur in 2016. We recognized the equity earnings of these deferred regulatory asset balances as a result of the OPUC SRRM Order we received in February 2015. In addition, a subsequent Order from the OPUC in the first quarter of 2016 resulted in a write-off of $2.8 million of interest in 2016.

Interest Expense, Net

Interest expense, net highlights include:

In thousands	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015	QTR Change	YTD Change
Interest expense, net	$9,718	$10,438	$19,454	$20,919	$(720)	$(1,465)

THREE AND SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Interest expense, net of amounts capitalized, decreased $0.7 million for the quarter and $1.5 million for the six month period primarily due to the redemption of $40 million of utility First Mortgage Bonds (FMBs) in June 2015 and the early retirement of $20 million of Gill Ranch's debt in December 2015.

Income Tax Expense

Income tax expense highlights include:

In thousands	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015	QTR Change	YTD Change
Income tax expense	$1,382	$1,414	$26,768	$20,497	$(32)	$6,271

THREE AND SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. Increases or decreases in income tax expense are correlated with changes in pre-tax income. Additionally, income tax expense during the six months ended June 30, 2016, as compared to 2015, was higher as 2015 tax expense benefited from the realization of deferred depletion benefits from 2013 and 2014.

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FINANCIAL CONDITION

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45% to 50% 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 the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and provide access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	June 30,		December 31,
	2016	2015	2015
Common stock equity(1)	51.7 %	49.2 %	47.5 %
Long-term debt(1)	36.8	38.8	34.6
Short-term debt, including current maturities of long-term debt	11.5	12.0	17.9
Total	100.0 %	100.0 %	100.0 %

(1) Ratios reflect debt balances net of any unamortized debt issuance costs.

Liquidity and Capital Resources

At June 30, 2016 we had $5.5 million of cash and cash equivalents compared to $4.5 million at June 30, 2015. We did not have restricted cash at June 30, 2016 compared to $4.5 million in restricted cash at June 30, 2015 held as collateral for the long-term debt outstanding at Gill Ranch, which we retired in December 2015. 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 same 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, short-term 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, 2016, we have Board authorization to issue up to $325 million of additional FMBs. 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 ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit, or other forms 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, 2016. However, if the credit risk-related contingent features underlying these contracts were triggered on June 30, 2016, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $5.9 million of collateral to our counterparties. See "Credit Ratings" below and Note 12.

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Other items that may have a significant impact on our liquidity and capital resources include pension contribution requirements and environmental expenditures.

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 "Application of Critical Accounting Policies—Accounting for Pensions and Postretirement Benefits" in the 2015 Form 10-K.

Gas Storage

Short-term liquidity for the gas storage segment is supported by cash balances, internal cash flow from operations, equity contributions from its parent company, and, if necessary, additional external financing.

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 and 2016-17 storage years, but overall prices are still lower than the long-term contracts that expired at the end of the 2013-14 storage year. While we expect continuing challenges for Gill Ranch in 2016, we do not anticipate material changes in our ability to access sources of cash for short-term liquidity.

Consolidated

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

Short-Term Debt

Our primary source of utility short-term liquidity is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans 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 and bank loans are 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, 2016 and 2015, our utility had short-term debt outstanding of $152.8 million and $190.3 million, respectively. The effective interest rate on short-term debt outstanding at June 30, 2016 and 2015 was 0.7% and 0.4%, respectively.

Credit Agreements

We have a $300 million credit agreement, with a feature that allows us to request increases in the total commitment amount, up to a maximum of $450 million. The 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, 2016 as follows:

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

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

Our credit agreement permits the issuance of letters of credit in an aggregate amount of up to $100 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreement is due and payable on or before the maturity date. There were no outstanding balances under this credit agreement at June 30, 2016 or 2015. 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, 2016 and 2015, with consolidated indebtedness to total capitalization ratios of 48.3% 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 the 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. The following table summarizes our current debt ratings:

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-2
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

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

Maturity and Redemption of Long-Term Debt

We did not retire any debt in the first six months of 2016. Over the next twelve months, $25 million of FMBs with a coupon rate of 5.15% and maturity in December 2016 are expected to be redeemed.

See Part II, Item 7, "Financial Condition—Contractual Obligations" in our 2015 Form 10-K for a schedule of long-term debt maturing over the next five years.

Cash Flows

Operating Activities

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	2016	2015	YTD Change
Cash provided by operating activities	$199,560	$167,484	$32,076

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. The significant factors contributing to the $32.1 million increase in operating cash flows were as follows:

- an increase of $20.1 million due to an increase in net deferred tax liabilities primarily due to the enactment of bonus depreciation;
- a net increase of $25.7 million from changes in working capital related to receivables, inventories and accounts payable reflecting lower gas prices and volumes sold in 2016 compared to 2015;
- an increase of $6.9 million from collections under the SRRM; offset by
- a decrease of $31.0 million from changes in deferred gas cost balances primarily due to the early refund of gas cost savings paid to customers in June 2016.

The non-cash pension expense recognized on the income statement for the six months ended June 30, 2016 was $2.7 million, compared to $3.0 million for the same period in 2015. Changes in pension expense are mitigated by our balancing account in Oregon; and therefore, net non-cash pension expenses are expected to remain relatively flat in the coming years.

During the six months ended June 30, 2016, we contributed $6.1 million to our utility's qualified defined benefit pension plan, compared to $5.8 million for the same period in 2015. The amount and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. See Note 7.

Bonus income tax depreciation for 2014 and 2015 was not enacted until December 19, 2014 and December 17, 2015, respectively. In both cases it was extended retroactively back to January 1 of the respective year. As a result, estimated income tax payments were made throughout 2014 and 2015 without the benefit of bonus depreciation for the year. This delayed the cash flow benefit of bonus depreciation until refunds could be requested and received. We received refunds of federal income tax overpayments of $2.0 million and $7.9 million in the second quarter of 2015 and the first quarter of 2016, respectively.

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 the near future. 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.

Ballot Measure 97 (Measure 97) was certified by the Oregon Secretary of State's office in June of 2016 to appear on the November 8, 2016 statewide ballot. Measure 97 amends Oregon's corporate minimum tax rules. We are currently evaluating the effect this proposed legislation would have on our consolidated financial position and results of operations, if enacted into law.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see "Financial Condition—Contractual Obligations" and Note 14 in the 2015 Form 10-K.

Investing Activities

Investing activity highlights include:

	Six Months Ended June 30,		
In thousands	2016	2015	YTD Change
Total cash used in investing activities	$(59,700)	$(61,316)	$1,616
Capital expenditures	(62,153)	(58,072)	(4,081)
Utility gas reserves	—	(1,945)	1,945

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. The $1.6 million decrease in cash used in investing activities was primarily due to non-recurring cash outflows from investments in gas reserves, restricted cash, and other items in the prior year, partially offset by higher utility capital expenditures.

Over the five-year period 2016 through 2020, total utility capital expenditures are estimated to be between $850 million and $950 million, including our proposed investment in an expansion of our Mist gas storage facility of approximately $125 million as well as continued refurbishments of an existing liquefied natural gas facility in Oregon over the next three years with an expected investment of approximately $25 million, and upgrading distribution infrastructure in Clark County, Washington, which could total approximately $25 million over the next five years. We are currently working with the project sponsor to finalize the project cost estimate for the Mist expansion project, which could change our estimated capital expenditures. The full capital expenditure for the Mist expansion is dependent upon receiving a notice to proceed from Portland General Electric, which we anticipate in the fall of 2016. The est

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imated level of utility capital expenditures over the next five years reflects assumptions for continued customer growth, technology investments, distribution system maintenance and improvements, and gas storage facilities maintenance. Most of the required funds are expected to be internally generated over the five-year period, and any remaining funding will be obtained through a combination of long-term debt and equity security issuances, with short-term debt and bridge financing providing liquidity.

In 2016, utility capital expenditures are estimated to be between $155 million and $175 million, which includes $10 million to $15 million for our Mist expansion project, of which a significant portion is dependent upon receiving a notice to proceed from the project customer, and non-utility capital investments are estimated to be less than $5 million. Gas storage segment capital expenditures in 2016 are expected to be paid from working capital and additional equity contributions from NW Natural as needed.

Financing Activities

Financing activity highlights include:

	Six Months Ended June 30,		
In millions	2016	2015	YTD Change
Total cash used in financing activities	$(138,608)	$(111,236)	$(27,372)
Change in short-term debt	(117,235)	(44,400)	(72,835)
Change in long-term debt	—	(40,000)	40,000

SIX MONTHS ENDED JUNE 30, 2016 COMPARED TO JUNE 30, 2015. The $27.4 million increase in cash used in financing activities was primarily due to higher repayments of short term loans and commercial paper of $72.8 million during the six months ended June 30, 2016. Partially offsetting the increase was repayment of long-term debt, for which we used $40 million in cash during the six months ended June 30, 2015.

Ratios of Earnings to Fixed Charges

For the six and twelve months ended June 30, 2016 and the twelve months ended December 31, 2015, our ratios of earnings to fixed charges, computed using the method outlined by the SEC, were 4.17, 3.39, and 3.00, respectively. For this purpose, earnings consist of net income before income taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. See Exhibit 12 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 “Application of Critical Accounting Policies and Estimates” in our 2015 Form 10-K. At June 30, 2016, our total estimated liability related to environmental sites is $120.4 million. See Note 13 and "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs".

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APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements in accordance with 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 accounting;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes;
- environmental contingencies; and
- impairment of long-lived assets.

There have been no material changes to the information provided in the 2015 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 2015 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.

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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, 2016. See Part II, Item 1A, "Risk Factors" in this report and Part II, Item 7A, "Quantitative and Qualitative Disclosures about Market Risk" in the 2015 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, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 13 and those proceedings disclosed and incorporated by reference in Part I, Item 3, “Legal Proceedings” in our 2015 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 2015 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, as amended, during the quarter ended June 30, 2016:
Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2)	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2)
Balance forward			2,124,528	$ 16,732,648
04/01/16-04/30/16	867	$ 51.82	—	—
05/01/16-05/31/16	17,814	57.60	—	—
06/01/16-06/30/16	1,044	59.50	—	—
Total	19,725	57.44	2,124,528	$ 16,732,648

(1) During the quarter ended June 30, 2016, 17,880 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 1,845 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, 2016, 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, 2017 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, 2016, no shares of our common stock were repurchased pursuant to this program. Since the program’s inception in 2000, we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

ITEM 6. EXHIBITS

See Exhibit Index attached hereto.

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SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)
Dated: August 2, 2016

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

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Quarterly Report on Form 10-Q
For the Quarter Ended June 30, 2016

Exhibit Number	Document
10.1	Form of Restricted Stock Unit Agreement between the Company and an executive officer dated as of July 27, 2016.
10.2	Amended and Restated Cash Retention Agreement between the Company and an executive officer, dated as of July 28, 2016.
10.3	Northwest Natural Gas Company Deferred Compensation Plan for Directors and Executives, effective January 1, 2005 and restated effective July 28, 2016.
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.	The following materials from Northwest Natural Gas Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, 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.