NORTHWEST NATURAL GAS CO
Form 10-Q
August 02, 2017

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, 2017

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", "smaller reporting company" and "emerging growth 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)	Emerging Growth Company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

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 28, 2017, 28,662,352 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, 2017

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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, which are subject to the safe harbors created by such Act. Forward-looking statements can be identified by words such as anticipates, assumes, intends, plans, seeks, projects, 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;
- ongoing continuation of past practices or patterns;
- future events or performance;
- trends, uncertainties, timing and cyclicality;
- risks;
- earnings and dividends;
- capital and other expenditures and allocation;
- capital or organizational structure;
- climate change and our role in a low carbon future;
- growth and profitability;
- customer rates or incentives;
- labor relations;
- workforce succession;
- commodity costs and volumes;
- gas reserves, volumes, investment and recovery;
- operational and maintenance performance and costs;
- energy policy infrastructure and preferences;
- efficacy of and exposure under derivatives and hedges;
- liquidity, funding sources, and financial positions;
- valuations;
- project and program development, expansion, or investment;
- pipeline capacity demand, location, and reliability;
- adequacy of property rights;
- procurement and development of gas supplies;
- estimated expenditures;
- competition;
- costs of compliance;
- credit exposures or collateral calls;
- rate or regulatory outcomes, prudency, recovery or refunds;
- impacts of, or changes in, laws, rules and regulations;
- tax positions, liabilities or refunds;
- levels and pricing of gas storage contracts and gas storage markets;
- outcomes, timing and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations, contributions, expectations and treatment under retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;

- effects of new or anticipated changes in accounting standards or pronouncements or application thereof;
- approval and adequacy of regulatory deferrals;
- effects and efficacy of regulatory mechanisms;
- local or national disasters, pandemic illness, terrorist activities, including cyber-attacks, data breaches, explosions, or other extreme events; 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, economic or financial performance. Important factors that could cause actual

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results to differ materially from those in the forward-looking statements are discussed in our 2016 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 June 30,		Six Months Ended June 30,	
In thousands, except per share data	2017	2016	2017	2016
Operating revenues	$136,238	$99,183	$433,561	$354,712
Operating expenses:				
Cost of gas	53,005	20,871	196,616	129,282
Operations and maintenance	38,546	35,962	78,966	74,901
Environmental remediation	2,611	1,893	9,565	6,922
General taxes	7,564	7,438	16,589	16,122
Depreciation and amortization	21,355	20,413	42,440	40,807
Total operating expenses	123,081	86,577	344,176	268,034
Income from operations	13,157	12,606	89,385	86,678
Other income (expense), net	958	513	1,839	(1,796)
Interest expense, net	9,717	9,718	19,593	19,454
Income before income taxes	4,398	3,401	71,631	65,428
Income tax expense	1,669	1,382	28,592	26,768
Net income	2,729	2,019	43,039	38,660
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $88 and $126 for the three months ended and $177 and $253 for the six months ended June 30, 2017 and 2016, respectively	137	143	273	337
Comprehensive income	$2,866	$2,162	$43,312	$38,997
Average common shares outstanding:				
Basic	28,648	27,510	28,641	27,479
Diluted	28,717	27,632	28,722	27,591
Earnings per share of common stock:				
Basic	$0.10	$0.07	$1.50	$1.41
Diluted	0.10	0.07	1.50	1.40
Dividends declared per share of common stock	0.4700	0.4675	0.9400	0.9350

See Notes to Unaudited Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2017	June 30, 2016	December 31, 2016
Assets:			
Current assets:			
Cash and cash equivalents	$20,854	$5,463	$3,521
Accounts receivable	31,908	23,353	66,700
Accrued unbilled revenue	13,896	14,175	64,946
Allowance for uncollectible accounts	(845)	(570)	(1,290)
Regulatory assets	37,504	49,004	42,362
Derivative instruments	1,530	7,445	17,031
Inventories	57,666	66,171	54,129
Gas reserves	16,072	15,707	15,926
Other current assets	13,419	21,312	24,728
Total current assets	192,004	202,060	288,053
Non-current assets:			
Property, plant, and equipment	3,333,668	3,146,631	3,208,816
Less: Accumulated depreciation	973,084	932,179	947,916
Total property, plant, and equipment, net	2,360,584	2,214,452	2,260,900
Gas reserves	92,020	108,286	100,184
Regulatory assets	348,284	344,969	357,530
Derivative instruments	162	3,541	3,265
Other investments	68,885	67,868	68,376
Other non-current assets	3,215	1,968	1,493
Total non-current assets	2,873,150	2,741,084	2,791,748
Total assets	$3,065,154	$2,943,144	$3,079,801

See Notes to Unaudited Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2017	June 30, 2016	December 31, 2016
Liabilities and equity:			
Current liabilities:			
Short-term debt	$—	$152,800	$53,300
Current maturities of long-term debt	61,991	24,987	39,989
Accounts payable	95,761	57,756	85,664
Taxes accrued	6,906	6,237	12,149
Interest accrued	5,966	5,793	5,966
Regulatory liabilities	28,041	27,300	40,290
Derivative instruments	4,734	3,471	1,315
Other current liabilities	31,683	35,289	35,844
Total current liabilities	235,082	313,633	274,517
Long-term debt	658,118	570,045	679,334
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	577,176	554,400	557,085
Regulatory liabilities	359,205	341,259	349,319
Pension and other postretirement benefit liabilities	219,718	219,049	225,725
Derivative instruments	3,466	474	913
Other non-current liabilities	146,960	144,285	142,411
Total deferred credits and other non-current liabilities	1,306,525	1,259,467	1,275,453
Commitments and contingencies (see Note 13)			
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 28,662, 27,550, and 28,630 at June 30, 2017 and 2016, and December 31, 2016, respectively	444,058	388,967	445,187
Retained earnings	428,049	417,857	412,261
Accumulated other comprehensive loss	(6,678)	(6,825)	(6,951)
Total equity	865,429	799,999	850,497
Total liabilities and equity	$3,065,154	$2,943,144	$3,079,801

See Notes to Unaudited Consolidated Financial Statements

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

	Six Months Ended June 30,	
In thousands	2017	2016
Operating activities:		
Net income	$43,039	$38,660
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	42,440	40,807
Regulatory amortization of gas reserves	8,031	7,647
Deferred income taxes	22,170	27,022
Qualified defined benefit pension plan expense	2,615	2,737
Contributions to qualified defined benefit pension plans	(7,250)	(6,120)
Deferred environmental expenditures, net	(6,817)	(5,521)
Regulatory disallowance of prior environmental cost deferrals	—	3,273
Amortization of environmental remediation	9,565	6,922
Other	1,268	2,121
Changes in assets and liabilities:		
Receivables, net	86,065	87,271
Inventories	(3,537)	4,525
Income taxes	(5,243)	3,710
Accounts payable	(22,063)	(17,141)
Interest accrued	—	(80)
Deferred gas costs	15,325	(9,295)
Other, net	8,623	13,022
Cash provided by operating activities	194,231	199,560
Investing activities:		
Capital expenditures	(94,318)	(62,153)
Other	(404)	2,453
Cash used in investing activities	(94,722)	(59,700)
Financing activities:		
Repurchases related to stock-based compensation	(2,034)	(1,042)
Proceeds from stock options exercised	1,309	5,374
Change in short-term debt	(53,300)	(117,235)
Cash dividend payments on common stock	(26,919)	(25,677)
Other	(1,232)	(28)
Cash used in financing activities	(82,176)	(138,608)
Increase in cash and cash equivalents	17,333	1,252
Cash and cash equivalents, beginning of period	3,521	4,211
Cash and cash equivalents, end of period	$20,854	$5,463
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalization	$18,011	$18,124
Income taxes paid (refunded)	9,081	(7,900)

See Notes to Unaudited Consolidated Financial Statements

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 NWN 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. 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 a fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2016 Annual Report on Form 10-K (2016 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.

2. SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are described in Note 2 of the 2016 Form 10-K. There were no material changes to those accounting policies during the six months ended June 30, 2017. 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 Commission (WUTC), which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

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Amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	June 30,		December 31,
In thousands	2017	2016	2016
Current:			
Unrealized loss on derivatives[(1)]	$4,625	$3,439	$1,315
Gas costs	859	9,571	6,830
Environmental costs[(2)]	6,724	9,610	9,989
Decoupling[(3)]	12,136	14,170	13,067
Other[(4)]	13,160	12,214	11,161
Total current	$37,504	$49,004	$42,362
Non-current:			
Unrealized loss on derivatives[(1)]	$3,466	$474	$913
Pension balancing[(5)]	55,358	48,761	50,863
Income taxes	36,591	40,106	38,670
Pension and other postretirement benefit liabilities	176,136	177,596	183,035
Environmental costs[(2)]	64,008	65,983	63,970
Gas costs	87	1,487	89
Decoupling[(3)]	1,993	1,776	5,860
Other[(4)]	10,645	8,786	14,130
Total non-current	$348,284	$344,969	$357,530

	Regulatory Liabilities		
	June 30,		December 31,
In thousands	2017	2016	2016
Current:			
Gas costs	$15,708	$12,501	$8,054
Unrealized gain on derivatives[(1)]	1,459	7,428	16,624
Other[(4)]	10,874	7,371	15,612
Total current	$28,041	$27,300	$40,290
Non-current:			
Gas costs	$2,719	$1,622	$1,021
Unrealized gain on derivatives[(1)]	162	3,541	3,265
Accrued asset removal costs[(6)]	350,828	332,627	341,107
Other[(4)]	5,496	3,469	3,926
Total non-current	$359,205	$341,259	$349,319

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

(2) Environmental costs relate to specific sites approved for regulatory deferral by the 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 the aforementioned 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.

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We believe all costs incurred and deferred at June 30, 2017 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
There were no material changes to the recently adopted accounting policies described in Note 2 of the 2016 Form 10-K during the six months ended June 30, 2017.

Recently Issued Accounting Pronouncements
STOCK COMPENSATION. On May 10, 2017, the FASB issued ASU 2017-09, "Stock Compensation - Scope of Modification Accounting." The purpose of the amendment is to provide clarity, reduce diversity in practice and reduce the cost and complexity when applying the guidance in Topic 718, related to a change to the terms or conditions of a share-based payment award. The ASU amends the scope of modification accounting for share-based payment arrangements and provides guidance on the types of changes to the terms or conditions of share-based payment awards to which an entity would be required to apply modification accounting under ASC 718. Specifically, an entity would not apply modification accounting if the fair value, vesting conditions and classification of the awards are the same immediately before and after the modification. The amendments in this update are effective for us beginning January 1, 2018. Early adoption is permitted and the amendments in this update should be applied prospectively to an award modified on or after the adoption date. We do not expect this standard to materially affect our financial statements and disclosures.

RETIREMENT BENEFITS. On March 10, 2017, the FASB issued ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post Retirement Benefit Cost." The ASU requires entities to disaggregate current service cost from the other components of net periodic benefit cost and present it with other current compensation costs for related employees in the income statement and to present the other components elsewhere in the income statement and outside of income from operations if that subtotal is presented. This ASU also limits capitalization of net periodic benefit cost to the service cost component. The amendments in this update are effective for us beginning January 1, 2018. Upon adoption, the ASU requires that changes to the income statement presentation of net periodic benefit cost be applied retrospectively, while changes to amounts capitalized must be applied prospectively. We are currently assessing the effect of this standard on our financial statements and disclosures and anticipate the service cost component will be recognized in operations and maintenance expense, and the non-service cost component will be recognized in other income (expense), net. While the ASU limits capitalization of net periodic benefit cost to the service cost component, for rate making purposes, we do not expect there to be a change. As a result, we expect that the non-service cost component previously capitalized, will be reclassified to a regulatory asset. We do not anticipate any impact on net income from the adoption of this ASU.

STATEMENT OF CASH FLOWS. On August 26, 2016, the FASB issued ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments." The ASU adds guidance pertaining to the classification of certain cash receipts and payments on the statement of cash flows. The purpose of the amendment is to clarify issues that have been creating diversity in practice, including the classification of proceeds from the settlement of insurance claims and proceeds from the settlement of corporate-owned life insurance policies. The amendments in this standard are effective for us beginning January 1, 2018. 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. Refer to Note 14 of the 2016 Form 10-K for our current lease commitments.

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. We do not expect this standard to have a material impact to our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." Subsequently, the FASB issued additional, clarifying amendments to address issues and questions regarding implementation of the new revenue recognition standard. 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 guidance also requires additional disclosures, both qualitative and quantitative, regarding the nature, amount, timing and uncertainty of revenue and cash flows. The new requirements prescribe either a full retrospective or simplified transition adoption method. We are currently analyzing our revenue streams, material contracts with customers, and the expanded disclosure requirements under the new standard. We are also evaluating our method of adoption and potential changes to our accounting policies, processes, systems and internal controls that may be required under the new standard. The new standard is effective for us beginning January 1, 2018.

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	2017	2016	2017	2016
Net income	$2,729	$2,019	$43,039	$38,660
Average common shares outstanding - basic	28,648	27,510	28,641	27,479
Additional shares for stock-based compensation plans (See Note 5)	69	122	81	112
Average common shares outstanding - diluted	28,717	27,632	28,722	27,591
Earnings per share of common stock - basic	$0.10	$0.07	$1.50	$1.41
Earnings per share of common stock - diluted	$0.10	$0.07	$1.50	$1.40

Additional information:				
Antidilutive shares	32	23	21	16

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

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facility and our North Mist gas storage expansion 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 2016 Form 10-K for further discussion of our segments.

Inter-segment transactions were immaterial 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
2017				
Operating revenues	$130,095	$6,088	$55	$136,238
Depreciation and amortization	19,894	1,461	—	21,355
Income (loss) from operations	11,860	1,599	(302)	13,157
Net income (loss)	2,137	756	(164)	2,729
Capital expenditures	54,265	1,129	—	55,394
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

	Six Months Ended June 30,			
In thousands	Utility	Gas Storage	Other	Total
2017				
Operating revenues	$422,821	$10,629	$111	$433,561
Depreciation and amortization	39,518	2,922	—	42,440
Income (loss) from operations	87,683	2,205	(503)	89,385
Net income (loss)	42,329	817	(107)	43,039
Capital expenditures	93,119	1,199	—	94,318
Total assets at June 30, 2017	2,792,011	256,396	16,747	3,065,154
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
Total assets at December 31, 2016	2,806,627	256,333	16,841	3,079,801

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 segment and other emphasize

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growth in operating revenues as opposed to margin because they do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

The following table presents additional segment information concerning utility margin:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2017	2016	2017	2016
Utility margin calculation:				
Utility operating revenues [1]	$130,095	$92,135	$422,821	$342,239
Less: Utility cost of gas	53,005	20,871	196,616	129,282
Environmental remediation expense	2,611	1,893	9,565	6,922
Utility margin	$74,479	$69,371	$216,640	$206,035

(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.

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 2016 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, 2017, 32,680 performance-based shares were granted under the LTIP based on target-level awards with a weighted-average grant date fair value of $57.05 per share. Award share payouts range from a threshold of 0% to a maximum of 200% based on achievement of EPS and Return on Invested Capital (ROIC) factors, which can be modified by a total shareholder return factor (TSR factor) relative to the performance of the Russell 2500 Utilities Index over the three-year performance period and a growth modifier based on a cumulative EBITDA measure. Fair value for the shares granted during the six months ended June 30, 2017 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	$59.90
Performance term (in years)	3.0
Quarterly dividends paid per share[1]	$0.4700
Expected dividend yield	3.09 %
Dividend discount factor	0.9156

(1) In addition to common stock shares, a participant also receives a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period.

As of June 30, 2017, there was $2.8 million of unrecognized compensation cost from LTIP grants, which is expected to be recognized through 2019.

Restricted Stock Units

During the six months ended June 30, 2017, 28,488 RSUs were granted under the LTIP with a weighted-average grant date fair value of $59.78 per share. 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. 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, 2017, there was $3.3 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2021.

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6. DEBT

Short-Term Debt
At June 30, 2017, we had no outstanding short-term debt.

Long-Term Debt
At June 30, 2017, we had long-term debt of $720.1 million, which included $6.6 million of unamortized debt issuance costs. Utility long-term debt consists of first mortgage bonds (FMBs) with maturity dates ranging from 2017 through 2046, interest rates ranging from 1.545% to 9.05%, and a weighted-average coupon rate of 5.083%.

Fair Value of Long-Term Debt
Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2 in the 2016 Form 10-K for a description of the fair value hierarchy.

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	2017	2016	2016
Gross long-term debt	$726,700	$601,700	$726,700
Unamortized debt issuance costs	(6,591)	(6,668)	(7,377)
Carrying amount	$720,109	$595,032	$719,323
Estimated fair value[1]	791,885	708,322	793,339

[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	2017	2016	2017	2016	2017	2016	2017	2016
Service cost	$1,870	$1,944	$99	$121	$3,740	$3,888	$197	$242
Interest cost	4,472	4,574	274	300	8,944	9,148	548	600
Expected return on plan assets	(5,112)	(5,017)	—	—	(10,225)	(10,034)	—	—
Amortization of prior service costs	31	58	(117)	(117)	63	116	(234)	(234)
Amortization of net actuarial loss	3,622	3,502	139	192	7,243	7,004	277	384
Net periodic benefit cost	4,883	5,061	395	496	9,765	10,122	788	992
Amount allocated to construction	(1,558)	(1,574)	(135)	(164)	(3,079)	(3,122)	(267)	(328)
Amount deferred to regulatory balancing account[1]	(1,508)	(1,593)	—	—	(3,035)	(3,220)	—	—

Net amount charged to expense	$1,817	$1,894	$260	$332	$3,651	$3,780	$521	$664

(1) The deferral of defined benefit pension plan 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 2016 Form 10-K.

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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	2017	2016	2017	2016
Beginning balance	$(6,815)	$(6,968)	$(6,951)	$(7,162)
Amounts reclassified to AOCL	—	—	—	—
Amounts reclassified from AOCL:				
Amortization of actuarial losses	225	269	450	590
Total reclassifications before tax	225	269	450	590
Tax (benefit) expense	(88)	(126)	(177)	(253)
Total reclassifications for the period	137	143	273	337
Ending balance	$(6,678)	$(6,825)	$(6,678)	$(6,825)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

For the six months ended June 30, 2017, we made cash contributions totaling $7.3 million to our qualified defined benefit pension plans. We expect further plan contributions of $12.2 million during the remainder of 2017.

Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Sections 401(a) and 401(k). Employer contributions totaled $2.8 million and $2.5 million for the six months ended June 30, 2017 and 2016, respectively.

See Note 8 in the 2016 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	2017	2016	2017	2016
Income taxes at statutory rates (federal and state)	$1,725	$1,351	$28,325	$25,959
Increase (decrease):				
Differences required to be flowed-through by regulatory commissions	66	65	1,584	1,583
Other, net	(122)	(34)	(1,317)	(774)
Total provision for income taxes	$1,669	$1,382	$28,592	$26,768
Effective tax rate	37.9%	40.6%	39.9%	40.9%

The effective income tax rate for the three and six months ended June 30, 2017, compared to the same period in 2016, decreased primarily as a result of AFUDC equity income and increased stock-based compensation deductions in 2017. See Note 9 in the 2016 Form 10-K for more detail on income taxes and effective tax rates.

The IRS Compliance Assurance Process (CAP) examination of the 2015 tax year was completed during the first quarter of 2017. There were no material changes to the return as filed. The 2016 tax year is subject to examination under CAP and the 2017 tax year CAP application has been accepted by the IRS.

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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	2017	2016	2016
Utility plant in service	$2,901,791	$2,783,883	$2,843,243
Utility construction work in progress	127,383	57,068	62,264
Less: Accumulated depreciation	925,589	890,028	903,096
Utility plant, net	2,103,585	1,950,923	2,002,411
Non-utility plant in service	299,366	297,809	299,378
Non-utility construction work in progress	5,128	7,871	3,931
Less: Accumulated depreciation	47,495	42,151	44,820
Non-utility plant, net	256,999	263,529	258,489
Total property, plant, and equipment	$2,360,584	$2,214,452	$2,260,900
Capital expenditures in accrued liabilities	$42,684	$11,345	$9,547

10. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of June 30, 2017. 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 through 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 investment under the original agreement, less accumulated amortization and deferred taxes, earns a rate of return.

The volumes produced from the wells under the amended agreement with Jonah 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	2017	2016	2016
Gas reserves, current	$16,072	$15,707	$ 15,926
Gas reserves, non-current	171,464	171,834	171,610
Less: Accumulated amortization	79,444	63,548	71,426
Total gas reserves(1)	108,092	123,993	116,110
Less: Deferred taxes on gas reserves	31,074	26,737	28,119

Net investment in gas reserves	$77,018	$97,256	$ 87,991

(1) Our net investment in additional wells included in total gas reserves was $6.3 million, $7.3 million and $6.7 million at June 30, 2017 and 2016 and December 31, 2016, respectively.

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

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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 balance sheet. If we do not develop this investment, then our maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in TWH was $13.4 million at June 30, 2017 and 2016 and December 31, 2016. See Note 12 in the 2016 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 2016 Form 10-K.

12. DERIVATIVE INSTRUMENTS

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

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

In the normal course of business, we 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

In thousands	2017	2016	31, 2016
Natural gas (in therms):			
Financial	490,780	517,980	477,430
Physical	495,751	398,980	535,450
Foreign exchange	$7,788	$ 7,254	$ 7,497

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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. In general, our commodity hedging for the current gas year is completed prior to the start of the gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. Hedge contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon. As of November 1, 2016 and 2015, we reached our target hedge percentage of approximately 75% for the 2016-17 and 2015-16 gas years. Hedge contracts entered into prior to our PGA filing, in September 2016, were included in the PGA for the 2016-17 gas year. Hedge contracts entered into after our PGA filing, and related to subsequent gas years, may be included in future PGA filings and qualify 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,			
	2017		2016	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$(5,172)	$ 216	$16,710	$ 267
Operating gain (loss)	(109)	—	840	—
Amounts deferred to regulatory accounts on balance sheet	5,263	(216)	(17,555)	(267)
Total loss in pre-tax earnings	$(18)	$ —	$(5)	$ —

	Six Months Ended June 30,			
	2017		2016	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$(16,515)	$ 224	$14,074	$ 201
Operating loss	(1,277)	—	(156)	—
Amounts deferred to regulatory accounts on balance sheet	17,347	(224)	(13,923)	(201)
Total loss in pre-tax earnings	$(445)	$ —	$(5)	$ —

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 gains of $0.3 million and remained flat for the three and six months ended June 30, 2017, respectively, from the settlement of natural gas financial derivative contracts. Whereas, we realized net losses of $7.6 million and $23.1 million for the three and six months ended June 30, 2016, respectively. 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, 2017 or 2016. 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 2017 or 2016. 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.

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Based upon current commodity financial swap and option contracts outstanding, which reflect unrealized losses of $6.7 million at June 30, 2017, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

	Credit Rating Downgrade Scenarios				
In thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ —	$ —	$ —	$ (2,150)	$ (4,829)
Without Adequate Assurance Calls	—	—	—	(2,150)	(3,576)

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our consolidated balance sheets. We and our counterparties have the ability to set-off 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 $0.9 million and a liability of $7.4 million as of June 30, 2017. As of June 30, 2016, our derivative position would have resulted in an asset of $8.1 million and a liability of $1.1 million. As of December 31, 2016, our derivative position would have resulted in an asset of $18.8 million and a liability of $0.7 million.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of customers. See Note 13 in our 2016 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, 2017. As of June 30, 2017 and 2016, and December 31, 2016, the net fair value was a liability of $6.5 million, an asset of $7.0 million, and an asset $18.1 million, respectively, using significant other observable, or level 2, inputs. No level 3 inputs were used in our derivative valuations, and there were no transfers between level 1 or level 2 during the six months ended June 30, 2017 and 2016. See Note 2 in the 2016 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, of those sites described herein, 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 a ROD is issued, we would seek to negotiate a consent decree or consent judgment for designing and implementing the remedy. We would 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, institutional controls such as legal restrictions on future property use, or natural recovery. 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 below.

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. In 2017, we received a claim made by the Yakama Nation against us and 29 other potentially responsible parties for costs related to the selection of remedial action and certain declaratory relief regarding NRD assessment costs related to the Multnomah Channel and Lower Willamette and Columbia Rivers. We are currently in the process of assessing the nature of, and our potential liability related to, the claim.

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 balance sheet:

	Current Liabilities			Non-Current Liabilities		
	June 30,		December 31,	June 30,		December 31,
In thousands	2017	2016	2016	2017	2016	2016
Portland Harbor site:						
Gasco/Siltronic Sediments	$1,485	$1,777	$ 869	$43,376	$42,991	$43,972
Other Portland Harbor	1,435	1,580	1,970	3,906	4,541	4,148
Gasco/Siltronic Upland site	9,441	9,033	10,657	49,319	51,433	49,183
Central Service Center site	31	112	73	—	—	—
Front Street site	829	984	906	10,788	7,739	7,786
Oregon Steel Mills	—	—	—	179	179	179
Total	$13,221	$13,486	$ 14,475	$107,568	$106,883	$105,268

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 sites. We are one of over one hundred PRPs to the Superfund site. In January 2017, the EPA issued its Record of Decision, which outlines its determination of a cleanup approach for the Portland Harbor site (Portland Harbor ROD). The Portland Harbor ROD presents the EPA's decision on remedial alternatives and outlines the clean-up plan for the entire Portland Harbor. The Portland Harbor ROD estimates the present value total cost at approximately $1.05 billion with an accuracy between -30% and

+50% of actual costs.

Our potential liability is 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. In addition, we are actively pursuing clarification and flexibility under the ROD in order to better understand our obligation under the clean-up. We are also participating in a non-binding allocation process in an effort to resolve our potential liability. The Portland Harbor ROD does not provide any additional clarification around allocation of costs among PRPs and, as a result of issuance of the Portland Harbor ROD, we have not modified any of our recorded liabilities at this time.

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

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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 cleanup can occur, and for regulatory oversight throughout the clean-up range from $44.9 million to $350 million. We have recorded a liability of $44.9 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. While we still believe liabilities associated with Gasco/Siltronic sediments site represent our largest exposure, we do have other potential exposures associated with the Portland Harbor ROD, including NRD costs and harbor wide clean-up costs (including downstream petroleum contamination), for which the allocations among the PRP's have not yet been determined.

The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased NRD assessment to estimate liabilities to support an early restoration-based settlement of NRD claims. One member of this Trustee council, the Yakama Nation, withdrew from the council in 2009, and in 2017, filed suit against the Company and 29 other parties seeking remedial costs and NRD assessment costs associated with the Portland Harbor, set forth in the complaint. The complaint seeks recovery of alleged costs totaling $0.3 million in connection with the selection of a remedial action for the Portland Harbor as well as declaratory judgment for unspecified future remedial action costs and for costs to assess the injury, loss or destruction of natural resources resulting from the release of hazardous substances at and from the Portland Harbor site. The Yakama Nation filed an amended complaint on June 20, 2017 addressing certain pleading defects and dismissing the State of Oregon. 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. The NRD liability is not included in the range of costs provided in the Portland Harbor ROD.

GASCO UPLANDS SITE. A predecessor of NW Natural, Portland Gas and Coke Company, 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 (VCP). 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 October 2016, ODEQ and NW Natural agreed to amend their VCP agreement to incorporate a portion of the Siltronic property adjacent to the Gasco site formerly owned by Portland Gas & Coke between 1939 and 1960 into the Gasco RA and FS. Previously we were conducting an investigation of manufactured gas plant constituents on the entire Siltronic uplands for ODEQ. Siltronic will be working with ODEQ directly on environmental impacts to the remainder of its property.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at 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.

OTHER SITES. In addition to those sites above, we have environmental exposures at three other sites: Central Service Center, Front Street and Oregon Steel Mills. We may have exposure at other sites that have not been identified at this time. 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

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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.

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.

In July 2017, ODEQ issued the PGM ROD. The ROD specifies the selected remedy, which requires a combination of dredging, capping, treatment, and natural recovery. In addition, the selected remedy also requires institutional controls and long-term inspection and maintenance. We revised the liability in the second quarter of 2017 to incorporate the estimated undiscounted cost of approximately $10.5 million for the selected remedy. 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. We plan to begin remedial design this fall and expect to complete dredging and installation during 2019.

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

Site Remediation and Recovery Mechanism (SRRM)
We have an 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, for those sites identified herein. In the February 2015 Order establishing the SRRM (2015 Order), the OPUC addressed outstanding issues related to the SRRM, which required us to forego the collection of $15 million out of approximately $95 million in total environmental remediation expenses and associated carrying costs. As a follow-up to the 2015 Order, the OPUC issued an additional Order in January 2016 (2016 Order) regarding the SRRM implementation which resulted in a $3.3 million non-cash charge primarily due to the disallowance of interest earned on the original allowance.

COLLECTIONS FROM OREGON CUSTOMERS. Under the SRRM collection process there are three types 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 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.

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 an equal and offsetting amount of our deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of the income statement.

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 2015 OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012 with the remaining two-thirds applied to costs at a rate of $5 million per year plus interest over the following 20 years. 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, 2017, 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	2017	2016	2016
Deferred costs and interest [1]	$50,131	$53,065	$53,039
Accrued site liabilities [2]	120,485	120,075	119,443
Insurance proceeds and interest	(99,884)	(97,547)	(98,523)
Total regulatory asset deferral[1]	$70,732	$75,593	$73,959
Current regulatory assets[3]	6,724	9,610	9,989
Long-term regulatory assets[3]	64,008	65,983	63,970

(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 those sites allocable to Oregon, 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. To the extent the utility earns at or below its authorized Return on Equity (ROE), remediation expenses and interest in excess of the $5 million tariff rider and $5 million insurance proceeds are recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10 million 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 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.

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For additional information regarding other commitments and contingencies, see Note 14 in the 2016 Form 10-K.

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

The following is management's assessment of Northwest Natural Gas Company's (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated results for the quarters ended June 30, 2017 and 2016. 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 2016 Annual Report on Form 10-K (2016 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
- NWN 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 2016 environmental order, 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 "2017 Outlook" in our 2016 Form 10-K for more information. Highlights include:

- added over 12,700 customers during the past twelve months for a growth rate of 1.8% at June 30, 2017;
- invested $94.3 million in our distribution system and facilities for growth and reliability; and
- continued construction on our North Mist Gas Storage Expansion Project. As of June 30, 2017 we have accrued $55 million of capital expenditures out of the $80 to $90 million of expenditures expected in 2017.

Key financial highlights include:

	Three Months Ended June 30,				
	2017		2016		$
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net income	$2,729	$0.10	$2,019	$0.07	$710
Utility margin	74,479		69,371		5,108
Gas storage operating revenues	6,088		6,992		(904)

THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Consolidated net income increased $0.7 million primarily due to the following factors:

- a $5.1 million increase in utility margin primarily due to customer growth and the effects of warmer weather in the prior period; partially offset by
- a $2.6 million increase in operating and maintenance expense largely from utility payroll and benefits increases; and
- a $0.9 million decrease in gas storage revenues largely due to lower revenues from our asset management agreements at our Mist storage facility and transportation capacity.

	Six Months Ended June 30,				
	2017		2016		$
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net income	$43,039	$1.50	$38,660	$1.40	$4,379
Adjustments:					
Regulatory environmental disallowance, net of taxes ($1.3 million for 2016)(1)	—	—	1,996	0.07	(1,996)
Adjusted consolidated net income(1)	$43,039	$1.50	$40,656	$1.47	$2,383
Utility margin	$216,640		$206,035		$10,605
Gas storage operating revenues	10,629		12,361		(1,732)

(1) Regulatory environmental disallowance of $3.3 million in 2016 includes $2.8 million recorded in utility other income (expense), net and $0.5 million recorded in utility operations and maintenance expense. Adjusted consolidated net income and EPS are non-GAAP financial measures based on the after-tax disallowance using the combined federal and state statutory tax rate of 39.5%. EPS is calculated using 28.7 million and 27.6 million diluted shares for the six months ended June 30, 2017 and 2016, respectively.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Consolidated net income increased $4.4 million including the environmental disallowance associated with a January 2016 OPUC Order in our SRRM docket described in the table above. Excluding the impact of this non-cash charge from the SRRM docket, adjusted consolidated net income increased $2.4 million primarily due to the following factors:

- a $10.6 million increase in utility margin primarily due to customer growth and the effects of colder than average weather in 2017 compared to a warmer than average winter in the prior period; partially offset by
- a $4.6 million increase in operating and maintenance expense largely from utility payroll and benefits increases; and
- a $1.7 million decrease in gas storage revenues largely due to lower revenues from our asset management agreements at our Mist storage facility and transportation capacity.

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DIVIDENDS

Dividend highlights include:

Per common share	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016	QTR Change	YTD Change
Dividends paid	$0.4700	$0.4675	$0.9400	$0.9350	$0.0025	$0.0050

The Board of Directors declared a quarterly dividend on our common stock of $0.47 cents per share, payable on August 15, 2017, to shareholders of record on July 31, 2017, reflecting an annual indicated dividend rate of $1.88 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. In 2016, approximately 89% of our utility gas customers were located in Oregon, with the remaining 11% in Washington. 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 "Most Recent General Rate Cases" 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, 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 their 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 2016, approximately 69% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 31% 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.

We continuously monitor the utility and evaluate the need for a rate case. Currently, we are contemplating filing an Oregon rate case in late 2017 or in 2018 with a Washington rate case thereafter.

Regulatory Proceeding Updates
During 2017, we were involved in the regulatory activities discussed below.

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SYSTEM INTEGRITY PROGRAM (SIP). Upon completion of our bare-steel replacement program, we filed a request to extend the SIP program. The OPUC suspended our filing and ordered additional processes, including involvement of other local distribution companies' (LDCs) in the state, before making a final decision. In 2016, we withdrew our request to extend the SIP program and instead focused our efforts on establishing guidelines for future safety cost trackers with the OPUC. In 2016, an all-party agreement establishing guidelines was filed with the OPUC and on March 6, 2017, the Commission issued an order adopting the agreement. The order allows LDCs to request safety cost recovery mechanisms under the guidelines established by the parties and requires LDCs to file annual safety project plans for OPUC and stakeholder review.

HEDGING. In 2014 the OPUC opened a docket to discuss broader gas hedging practices across gas utilities in Oregon. This docket was divided into 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, and seeking an agreement through discussions with the parties. After the second phase is complete, a status report or other filing will be submitted to the OPUC, and the remainder of the process will be determined at that time. Currently, we anticipate resolution of the docket in the second half of 2017.

The WUTC also conducted an investigation into the hedging practices of gas utilities operating in Washington, and considered whether it should require gas utilities to implement certain hedging practices. During 2016, the WUTC received and reviewed comments from all parties and issued a policy statement on March 13, 2017 outlining their expectations. The policy statement supports risk-responsive hedging strategies that are adaptable to variability in the market and requires gas utilities to submit with their 2017 PGA a preliminary hedging plan that outlines the utilities' intended path to incorporate risk-responsive hedging strategies. Beginning with the 2018 PGA, gas utilities must submit an annual comprehensive hedging plan that supports integration of risk responsive strategies into their hedging framework. Beginning with the 2019 PGA filing, utilities must provide a full strategy implementation plan for years 2020 and beyond. We are currently evaluating the WUTC order to determine its impact to our current hedging practices, and plan to submit our preliminary hedging plan with our 2017 PGA, as directed by the WUTC.

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. In 2017, all parties agreed and hired a third-party consultant to perform the study and are continuing to facilitate completion of the work directed by the OPUC. We expect completion of this study in the second half of 2017.

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 have worked with the stakeholders to reach common ground and are contemplating our next steps for this program.

INTEGRATED RESOURCE PLAN (IRP). We filed our 2016 Oregon and Washington IRPs on August 26, 2016. We received a letter of compliance from the WUTC in December 2016 and acknowledgment by the OPUC in February 2017. The IRP included analysis of different growth scenarios and corresponding resource acquisition strategies. The analysis is needed to develop supply and demand resource requirements, consider uncertainties in the planning process, and to establish a plan for providing reliable and low cost natural gas service.

GAS INCIDENT INVESTIGATION. On October 19, 2016, there was a natural gas explosion in Portland, Oregon after a third-party contractor damaged a NW Natural service line. The contractor was not working for NW Natural at the time. NW Natural and local authorities responded to the event and evacuated the necessary building prior to the ignition. No fatalities or life-threatening injuries were sustained. On March 30, 2017, the OPUC released its investigation report regarding the incident, finding that NW Natural followed federal emergency response requirements. NW Natural did not receive any fines or penalties as a result of the report or the incident. We continue to focus on safety and enhancements to our incident response and reporting procedures, both of which are operational priorities. We will also continue to partner with other first responders in our community for on-site emergency response coordination.

DEPRECIATION STUDY. Under OPUC regulations, the utility is required to file a depreciation study every five years to update or justify maintaining the existing depreciation rates. In December 2016, we filed the required depreciation study with the Commission and it is currently under review. We do not anticipate the study to materially change our current depreciation rates.

HOLDING COMPANY APPLICATION. In February 2017, we filed applications with the OPUC, WUTC, and CPUC for approval to reorganize under a holding company structure. The filing of regulatory applications is the first of many steps required to form a holding company. We expect that the regulatory process will take six to nine months, and will result in the OPUC, WUTC and CPUC authorizing a holding company structure subject to certain restrictions, or "ring-fencing" provisions applicable to NW Natural, the entity that currently, and would continue to, house our utility operations. In July 2017, the parties to the proceeding jointly agreed to suspend the OPUC procedural schedule and engage in a settlement process. The settlement process is ongoing, and we expect a resolution to the OPUC docket by settlement or otherwise by the end of 2017. We continue to work with the WUTC and CPUC. We do not expect a material operational or financial impact to our business as a result of the contemplated reorganization. For further discussion of our holding company application, see Part II, Item 7 "Results of Operations—Regulatory Matters—Regulatory Proceeding Updates" in our 2016 Form 10-K.

MULTI-FAMILY TARIFF. In June 2017, we filed a request to create a multi-family tariff to establish an optional program to serve the mixed-use, multi-family residential market. Under the tariff, NW Natural would provide up front incentives for builders to offset the initial cost of installing natural gas piping to individual units, and then recover the costs of the incentives through a fixed charge on the customer's monthly bills. In July 2017, the OPUC approved the tariff allowing us to further serve the multi-family customer sector.

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 costs under spot purchases as well as contract supplies, gas costs hedged with financial derivatives, gas costs 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 2016-17 gas year (November 1, 2016 - October 31, 2017) hedged at 75% of our forecasted sales volumes, including 48% in financial swap and option contracts and 27% in physical gas supplies. As part of the guidance issued by the WUTC on hedging and our open hedge docket with the OPUC, we are evaluating our hedge strategies for Oregon and Washington.

In addition to the amount hedged for the current gas contract year, we are also hedged in future years at approximately 60% for the 2017-18 gas year and between 4% and 22% for annual requirements over the subsequent five gas years as of June 30, 2017. 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 gas storage inventory levels may increase or decrease with storage expansion, changes in storage contracts with third parties, variations in the heat content of the gas, 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 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 2015-16 and 2016-17 gas years, we selected the 80% and 90% 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. For the 2015-16 and 2016-17 periods, we selected the 80% and 90% deferral option, respectively. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2015 and 2016, the ROE threshold was 10.60%, and 11.06%, respectively. There were no refunds required for 2015. We filed the 2016 earnings test in May 2017 and it was approved by the Commission in July 2017. As a result, we were not subject to a customer refund adjustment for 2016.

GAS RESERVES. In 2011, the OPUC approved the Encana gas reserves transaction to provide long-term gas price protection for our utility customers and determined our costs under the agreement would be recovered, on an ongoing basis, through our annual PGA mechanism. Gas produced from our interests is sold at then prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are included in our cost of gas. 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 response to Encana's sale of its interest in the Jonah field located in Wyoming to Jonah Energy. Under our amended agreement with Jonah Energy, 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 did not have the opportunity to participate in additional wells during 2015, 2016, or the six months ended June 30, 2017, but we may have the opportunity in the future.

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.

WARM. 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. The collections of any unbilled WARM amounts are deferred and earn a carrying charge until collected in the PGA the following year. 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, 2017, 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. 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.

Under the SRRM collection process there are three types of deferred environmental remediation expense:

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- 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.

In addition, the SRRM 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 an equal and offsetting amount of our deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of the income statement. See Note 13 in our 2016 Form 10-K.

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:

Annual spend
Less: $5 million base rate 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) Base rate 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.

To the extent the utility earns at or below its authorized Return on Equity (ROE), remediation expenses and interest in excess of the $5 million tariff rider and $5 million of insurance proceeds are recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the $10 million with those earnings that exceed its authorized ROE.

For 2016, we have performed this test, which we submitted to the OPUC in May 2017, and we do not expect an earnings test adjustment for 2016 based on our results.

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 carrying charges on amounts deferred for costs associated with services provided to Washington customers to 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 was made.

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, excluding interest, were $3.0 million and $3.2 million during the six months ended June 30, 2017 and 2016, respectively.

INTERSTATE STORAGE AND OPTIMIZATION SHARING. In 2017, we received regulatory approval to refund an interstate storage credit of $11.7 million to our Oregon utility customers. Of this amount, $10.8 million was reflected in their June bills with the remainder to be credited in the third quarter. The interstate storage credit approved for refund in June 2016 was approximately $9.4 million. The 2017 and 2016 customer credits are part of our regulatory incentive sharing mechanism related to non-utility Mist storage and asset management services. The Washington share of interstate storage and optimization revenues is included in the Washington PGA.

For a discussion of other rate mechanisms, see Part II, Item 7, “Results of Operations—Regulatory Matters—Rate Mechanisms in our 2016 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, WARM, 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, but not eliminate, the volatility of customer bills and our utility’s earnings. See "Regulatory Matters—Rate Mechanisms" above.

Utility segment highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
Dollars and therms in thousands, except EPS data	2017	2016	2017	2016	QTR Change	YTD Change
Utility net income	$2,137	$507	$42,329	$36,359	$ 1,630	$5,970
EPS - utility segment	0.07	0.02	1.47	1.32	0.05	0.15
Gas sold and delivered (in therms)	234,643	192,933	702,282	565,482	41,710	136,800
Utility margin[(1)]	$74,479	$69,371	$216,640	$206,035	$ 5,108	$10,605

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

THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. The primary factors contributing to the $1.6 million or $0.05 per share increase in utility net income were as follows:

- a $5.1 million increase in utility margin primarily due to:
  - a $1.7 million increase from customer growth; offset by
  - a $0.5 million decrease in gas cost incentive sharing due to actual gas prices being higher than those estimated in the 2016-17 PGA.
  - a portion of the remaining increase was due to the effects of warmer weather in 2016. Weather impacts utility margins from our Washington customers where we do not have a weather normalization mechanism in place and our Oregon customers who opted out of weather normalization.
- a $0.4 million increase in other income (expense), net, primarily due to earning equity AFUDC;
-

a $2.0 million increase in operations and maintenance expense largely from payroll and benefits due to increased headcount, general salary increases, and higher health care costs; and

- a $0.9 million increase in depreciation expense primarily due to additional capital expenditures.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. The primary factors contributing to the $6.0 million or $0.15 per share increase in utility net income were as follows:

- a $10.6 million increase in utility margin primarily due to:

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a $4.2 million increase from customer growth; offset by
a $3.2 million decrease in gains from gas cost incentive sharing due to actual gas prices being lower than those estimated in the 2016-17 PGA, but not by the same magnitude as in the prior period.
a portion of the remaining increase was due to the effects of colder than average weather in 2017 compared to a warmer than average winter in the prior period.

- a $3.4 million increase in other income (expense), net, primarily due to the environmental interest disallowance recognized in 2016 and earning additional equity AFUDC; partially offset by
- a $2.8 million increase in operations and maintenance expense largely from payroll and benefits due to increased headcount, general salary increases, and higher health care costs; and
- a $1.8 million increase in depreciation expense primarily due to additional capital expenditures.

Total utility volumes sold and delivered in the three months ended June 30, 2017 increased 22% over the same period in 2016 primarily due to the return to average weather after warmer weather in the prior period. As compared to the same period in 2016, weather was 70% colder during the three months ended June 30, 2017. For the six months ended June 30, 2017, total utility volumes sold and delivered increased 24% due to the impact of 44% colder weather during the first half of 2017, as compared to the prior period. In addition, weather was 12% colder than average for the six months ended June 30, 2017.

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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	2017	2016	2017	2016	QTD Change	YTD Change
Utility volumes (therms):						
Residential and commercial sales	113,869	82,625	441,392	325,499	31,244	115,893
Industrial sales and transportation	120,774	110,308	260,890	239,983	10,466	20,907
Total utility volumes sold and delivered	234,643	192,933	702,282	565,482	41,710	136,800
Utility operating revenues:						
Residential and commercial sales	$117,296	$82,509	$397,573	$320,181	$34,787	$77,392
Industrial sales and transportation	14,791	10,972	33,694	28,636	3,819	5,058
Other revenues	1,168	1,102	2,543	2,513	66	30
Less: Revenue taxes	3,160	2,448	10,989	9,091	(712)	(1,898)
Total utility operating revenues	130,095	92,135	422,821	342,239	37,960	80,582
Less: Cost of gas	53,005	20,871	196,616	129,282	(32,134)	(67,334)
Less: Environmental remediation expense	2,611	1,893	9,565	6,922	(718)	(2,643)
Utility margin	$74,479	$69,371	$216,640	$206,035	$5,108	$10,605
Utility margin:[1]						
Residential and commercial sales	$65,965	$60,888	$197,005	$184,372	$5,077	$12,633
Industrial sales and transportation	7,565	7,084	16,257	15,285	481	972
Miscellaneous revenues	1,165	1,097	2,538	2,503	68	35
Gain (loss) from gas cost incentive sharing	(113)	412	838	4,066	(525)	(3,228)
Other margin adjustments	(103)	(110)	2	(191)	7	193
Utility margin	$74,479	$69,371	$216,640	$206,035	$5,108	$10,605
Degree days						
Average[2]	691	691	2,546	2,562	—	(16)
Actual	684	403	2,853	1,988	70%	44%
Percent colder (warmer) than average weather[2]	(1)%	(42)%	12%	(22)%		

	As of June 30,		
Customers - end of period:	2017	2016	Change
Residential customers	662,376	650,584	11,792
Commercial customers	67,580	66,604	976
Industrial customers	1,012	1,003	9
Total number of customers	730,968	718,191	12,777
Customer growth (12 month rolling):			
Residential customers	1.8%		
Commercial customers	1.5%		
Industrial customers	0.9%		
Total customer growth	1.8%		

(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 of heating 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, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	QTR Change	YTD Change
Volumes (therms):						
Residential sales	68,697	47,069	278,347	202,301	21,628	76,046
Commercial sales	45,172	35,556	163,045	123,198	9,616	39,847
Total volumes	113,869	82,625	441,392	325,499	31,244	115,893
Operating revenues:						
Residential sales	$76,558	$53,599	$265,126	$214,299	$22,959	$50,827
Commercial sales	40,738	28,910	132,447	105,882	11,828	26,565
Total operating revenues	$117,296	$82,509	$397,573	$320,181	$34,787	$77,392
Utility margin:						
Residential:						
Sales	$45,043	$35,429	$150,370	$117,090	$9,614	$33,280
Weather normalization	(730)	4,735	(11,780)	13,966	(5,465)	(25,746)
Decoupling	921	1,776	(1,133)	(2,159)	(855)	1,026
Total residential utility margin	45,234	41,940	137,457	128,897	3,294	8,560
Commercial:						
Sales	18,125	14,993	58,231	45,898	3,132	12,333
Weather normalization	(222)	1,737	(4,511)	5,483	(1,959)	(9,994)
Decoupling	2,829	2,218	5,828	4,094	611	1,734
Total commercial utility margin	20,732	18,948	59,548	55,475	1,784	4,073
Total utility margin	$65,966	$60,888	$197,005	$184,372	$5,078	$12,633

THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 31.2 million therms, or 38%, due to customer growth in the current period and warmer weather in the second quarter of 2016, as compared to the second quarter of 2017;
- operating revenues increased $34.8 million, due to a 38% increase in sales volumes; and
- utility margin increased $5.1 million, due to customer growth and warmer weather in the prior period.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 115.9 million therms, or 36%, due to customer growth and colder than average weather in the first half of 2017;
- operating revenues increased $77.4 million, due to a 36% increase in sales volumes; and
- utility margin increased $12.6 million, due to customer growth and the effects of colder than average weather in 2017 compared to warmer than average weather in the prior period.

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 which becomes effective 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, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	QTR Change	YTD Change
Volumes (therms):						
Industrial - firm sales	7,637	7,122	18,013	16,546	515	1,467
Industrial - firm transportation	38,897	35,518	87,626	79,719	3,379	7,907
Industrial - interruptible sales	13,204	11,322	30,181	26,372	1,882	3,809
Industrial - interruptible transportation	61,036	56,346	125,070	117,346	4,690	7,724
Total volumes	120,774	110,308	260,890	239,983	10,466	20,907
Utility margin:						
Industrial - firm and interruptible sales	$2,775	$2,613	$6,115	$5,776	$ 162	$ 339
Industrial - firm and interruptible transportation	4,790	4,471	10,142	9,509	319	633
Industrial - sales and transportation	$7,565	$7,084	$16,257	$15,285	$ 481	$ 972

THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Sales and transportation volumes increased by 10.5 million therms and utility margin increased $0.5 million due to higher usage from warmer weather in the prior period and increased usage from higher production load.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Sales and transportation volumes increased by 20.9 million therms and utility margin increased $1.0 million due to higher usage from colder than average weather in 2017 compared to warmer than average weather in the prior year and increased usage from higher production load.

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 2016 Form 10-K.

Cost of gas highlights include:

Dollars and therms in thousands	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	QTR Change	YTD Change

Cost of gas	$53,005	$20,871	$196,616	$129,282	$32,134	$67,334
Volumes sold (therms)[1]	134,710	101,069	489,586	368,417	33,641	121,169
Average cost of gas (cents per therm)	$0.39	$0.21	$0.40	$0.35	$0.18	$0.05
Gain (loss) from gas cost incentive sharing[2]	(113)	412	838	4,066	(525)	(3,228)

(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, 2017 COMPARED TO JUNE 30, 2016. Cost of gas increased $32.1 million reflecting a 33% increase in volumes due to warmer weather in 2016, as compared to 2017, customer growth, and a $19.4 million refund to customers in 2016 from lower than projected market prices.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Cost of gas increased $67.3 million reflecting a 33% increase in volumes due to colder than average weather in 2017 compared to warmer than average weather in the prior period, customer growth, and a $19.4 million refund to customers in 2016 from lower than projected market prices.

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	2017	2016	2017	2016	QTR Change	YTD Change
Operating revenues	$6,088	$6,992	$10,629	$12,361	$(904)	$(1,732)
Operating expenses	4,489	4,112	8,424	7,756	377	668
Gas storage net income	756	1,439	817	2,175	(683)	(1,358)
EPS - gas storage segment	0.03	0.05	0.03	0.08	(0.02)	(0.05)

THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Our gas storage segment net income decreased $0.7 million or $0.02 per share primarily due to the following factors:

- a $0.9 million decrease in gas storage revenues largely due to lower asset management revenues from our Mist facility and transportation capacity; and
- a $0.4 million increase in operating expenses largely due to pipeline and compressor maintenance at our Gill Ranch facility.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Our gas storage segment net income decreased $1.4 million or $0.05 per share primarily due to the following factors:

- a $1.7 million decrease in gas storage revenues largely due to lower asset management revenues from our Mist facility and transportation capacity; and
- a $0.7 million increase in operating expenses largely due to pipeline and compressor maintenance at our Gill Ranch facility.

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 contracted both our Mist and Gill Ranch facilities for the 2017-18 gas storage year. Our Mist facility remains under long-term contracts at similar prices to prior periods. Our Gill Ranch facility is contracted with approximately half of the capacity in firm contracts at slightly higher prices than the prior gas storage year. The remaining capacity at the Gill Ranch facility is under asset management agreements with a third-party and is subject to market pricing.

Though prices at our Gill Ranch facility have improved slightly over the last several years, prices continue to remain low relative to our original long-term contracts, which ended primarily in the 2013-14 gas storage year. In the future, we may see continued price improvement or 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

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summer/winter natural gas price spreads, gas price volatility, and gas storage values, but there can be no assurance that this will result.

In October 2015, a significant natural gas leak occurred at an unaffiliated southern California gas storage facility that persisted into early 2016. At this time, we do not know the long-term effects of this incident on gas storage prices. In September 2016, legislation was passed and signed into law by the Governor of California in response to the incident, which directed the California Department of Oil Gas and Geothermal Resources (DOGGR) to develop new regulations for gas storage wells. On May 19, 2017, DOGGR sent a public notice related to Requirements for California Underground Gas Storage Projects, the proposed regulations issued in the formal rulemaking, with a public comment period, which ended in July 2017. We expect final rules to be issued in the second quarter of 2018. The draft DOGGR regulations focus on implementing a risk based well integrity management program that utilizes well risk management plans and compliance plans to set well integrity testing plans and schedules, implements real-time well monitoring requirements, new leak detection procedures and requires the implementation of tubing on packer for all wells that make contact with the reservoir. While the regulations are still under development and their ultimate impact is unknown, we are working with DOGGR to understand the rules and how the Gill Ranch facility's risk profile may impact the timing and extent of our compliance efforts as well as our capital expenditures and ongoing operations and maintenance costs. The timeline for implementation of the rules will not be set until the regulations are finalized next year. We expect the timeline to focus on testing of all wells within 2 to 15 years of the issuance of the regulations.

In addition, the US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA) is developing new regulations that will apply to all underground natural gas storage facilities in the United States which includes our operations in California and Oregon.

If such new regulation and legislation require significant capital and on-going spending to upgrade or maintain the Gill Ranch facility, if we are unsuccessful in identifying new higher value customers, if future storage values do not improve, if an increased demand and other favorable market conditions for natural gas storage do not materialize, and/or volatility does not return to the gas storage market, 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 $193.6 million at June 30, 2017. We continue to assess these conditions along with all strategic alternatives and their impact on the value of the asset on an ongoing basis. Refer to Note 2 in our 2016 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 development activities. There were no significant changes in our other activities during the six months ended June 30, 2017. 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	2017	2016	2017	2016

					QTR Change	YTD Change
Operations and maintenance	$38,546	$35,962	$78,966	$74,901	$2,584	$4,065

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THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Operations and maintenance expense increased $2.6 million reflecting higher utility payroll and benefits due to increased headcount, general salary increases, and higher health care costs as well as increased pipeline and compressor maintenance costs at our Gill Ranch facility.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Operations and maintenance expense increased $4.1 million reflecting higher utility payroll and benefits due to increased headcount, general salary increases, and higher health care costs as well as increased pipeline and compressor maintenance costs at our Gill Ranch facility.

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 both the six months ended June 30, 2017 and 2016.

Other Income (Expense), Net

Other income (expense), net highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
In thousands	2017	2016	2017	2016	QTR Change	YTD Change
Other income (expense), net	$958	$513	$1,839	$(1,796)	$ 445	$ 3,635

THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Other income (expense), net, increased $0.4 million primarily due to increased earnings of $0.5 million from the equity portion of AFUDC.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Other income (expense), net, increased $3.6 million primarily due to the January 2016 Order from the OPUC, which resulted in a $2.8 million interest disallowance in 2016. In addition, other income (expense), net benefited by $0.8 million from an increase in the equity portion of AFUDC.

Interest Expense, Net

Interest expense, net highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
In thousands	2017	2016	2017	2016	QTR Change	YTD Change
Interest expense, net	$9,717	$9,718	$19,593	$19,454	$ (1)	$ 139

THREE MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Interest expense, net remained flat overall. However, interest expense increased by $0.4 million due to the issuance of long-term debt in December 2016 and was offset by an increase of $0.4 million from the interest-related portion of AFUDC.

SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. Interest expense, net remained flat overall. However, interest expense increased by $0.8 million due to the issuance of long-term debt in December 2016 and was partially offset by an increase of $0.7 million from the interest-related portion of AFUDC.

Income Tax Expense

Income tax expense highlights include:

In thousands	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016	QTR Change	YTD Change
Income tax expense	$1,669	$1,382	$28,592	$26,768	$ 287	$ 1,824

THREE AND SIX MONTHS ENDED JUNE 30, 2017 COMPARED TO JUNE 30, 2016. The increase in income tax expense was correlated with the change in pre-tax income.

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, 2017	June 30, 2016	December 31, 2016
Common stock equity	54.6 %	51.7 %	52.4 %
Long-term debt	41.5	36.8	41.9
Short-term debt, including current maturities of long-term debt	3.9	11.5	5.7
Total[(1)]	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, 2017 we had $20.9 million of cash and cash equivalents compared to $5.5 million at June 30, 2016 due to higher cash collections from customers as a result of colder than average weather, especially in the first quarter of 2017, and lower working capital requirements. 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, the sale of long-term debt, and issuances of equity. Utility long-term debt and equity issuance 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, 2017, we have Board authorization to issue up to $175 million of additional FMBs. We also have OPUC approval to issue up to $175 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 required to post collateral at June 30, 2017. However, if the credit risk-related contingent features underlying these contracts were triggered on June 30, 2017, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $4.8 million in collateral with our counterparties. See "Credit Ratings" below and Note 12.

Other items that may have a significant impact on our liquidity and capital resources include pension contribution requirements, discontinuation of bonus tax depreciation 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 2016 Form 10-K.

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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 firm contract prices over the last several 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 2017, 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, 2017, our utility had no short-term debt outstanding compared to $152.8 million at June 30, 2016 due to lower working capital needs and net proceeds from our equity issuance and issuances of long-term debt instruments in November and December 2016, respectively. The effective interest rate on short-term debt outstanding at June 30, 2016 was 0.8%.

Credit Agreements
We have a $300 million credit agreement, with a feature that allows the Company 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, 2017 as follows:
In millions

Lender rating, by category	Loan Commitment
AA/Aa	$ 201
A/A	99
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. The principal amount of borrowings under the credit agreement is due and payable on the maturity date. There were no outstanding balances under this credit agreement at June 30, 2017 or 2016. 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, 2017 and 2016, with consolidated indebtedness to total capitalization ratios of 45.4% and 48.3%, 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

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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 Retirement of Long-Term Debt

We did not retire any debt in the six months ended June 30, 2017. Over the next twelve months, $40 million of FMBs with a coupon rate of 7.00% and maturity in August 2017 and $22 million of FMBs with a coupon rate of 6.60% and maturity in March 2018 are expected to be retired.

See Part II, Item 7, "Financial Condition—Contractual Obligations" in our 2016 Form 10-K for 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	2017	2016	YTD Change
Cash provided by operating activities	$194,231	$199,560	$(5,329)

SIX MONTHS ENDED JUNE 30, 2017 COMPARED to JUNE 30, 2016. The significant factors contributing to the $5.3 million decrease in cash flows provided by operating activities were as follows:

- a net decrease of $14.2 million from changes in working capital related to receivables, inventories, and accounts payable reflecting colder than average weather in 2017 compared to weather in the prior period;
-

a decrease of $13.6 million from changes in tax-related accounts primarily due to decreases from changes in accrued taxes and net deferred tax liabilities primarily due to the continuation of bonus depreciation in December 2016; partially offset by

- an increase of $24.6 million from changes in deferred gas cost balances due to an increase in natural gas prices compared to the prior year, which remained lower than those embedded in the PGA.

The non-cash qualified defined benefit pension expense recognized on the income statement for the six months ended June 30, 2017 and 2016 was $2.6 million and $2.7 million, respectively. 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, 2017, we contributed $7.3 million to our utility's qualified defined benefit pension plan, compared to $6.1 million for the same period in 2016. 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 2015 was not enacted until December 18, 2015, which was extended retroactively back to January 1, 2015. As a result, estimated income tax payments were made throughout 2015 without the benefit of bonus depreciation for the year. This delayed the cash flow benefit of bonus depreciation until a refund could be requested and received. We received a refund of federal income tax overpayments of $7.9 million in the first quarter of 2016. As a result of the Federal Protecting Americans From Tax Hikes Act of 2015, bonus depreciation is now enacted through 2019. Accordingly, we do not anticipate similar refunds from income tax overpayments related to bonus depreciation, in the near future.

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 2016 Form 10-K.

Investing Activities

Investing activity highlights include:

	Six Months Ended June 30,		
In thousands	2017	2016	YTD Change
Total cash used in investing activities	$(94,722)	$(59,700)	$(35,022)
Capital expenditures	(94,318)	(62,153)	(32,165)

SIX MONTHS ENDED JUNE 30, 2017 COMPARED to JUNE 30, 2016. The $35.0 million increase in cash used in investing activities was primarily due to higher capital expenditures primarily related to our North Mist Gas Storage Expansion Project as well as customer growth, system reinforcement, technology, and facilities.

Over the five-year period 2017 through 2021, total utility capital expenditures are estimated to be between $850 and $950 million. This range includes the total estimated cost of our North Mist gas storage facility expansion, which is approximately $128 million. The majority of the North Mist capital expenditures, $80 million to $90 million, are expected in 2017, with the remaining investment in 2018. We anticipate placing the expansion into service for the winter of 2018-19. Our five-year capital expenditure range also includes estimated capital expenditures between $75 million to $85 million related to planned upgrades and refurbishments to storage facilities, including our existing liquefied natural gas facilities in Oregon and our Mist storage facility. In addition, we plan to spend approximately $20 million to upgrade distribution infrastructure in Clark County, Washington through 2019. The estimated level of utility capital expenditures through 2021 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, with short-term and long-term debt and bridge financing providing liquidity.

In 2017, utility capital expenditures are estimated to be between $225 and $250 million, and non-utility capital investments of less than $5 million. Additional spend for gas storage and other investments during and after 2017 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 thousands	2017	2016	YTD Change
Total cash used in financing activities	$(82,176)	$(138,608)	$56,432
Change in short-term debt	(53,300)	(117,235)	63,935
Proceeds from stock option exercises	1,309	5,374	(4,065)

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SIX MONTHS ENDED JUNE 30, 2017 COMPARED to JUNE 30, 2016. The $56.4 million decrease in cash used in financing activities was primarily due to lower repayments of $63.9 million of short-term loans and commercial paper compared to the prior period, slightly offset by $4.1 million lower proceeds received from fewer stock option exercises.

Ratios of Earnings to Fixed Charges

For the six and twelve months ended June 30, 2017, and the twelve months ended December 31, 2016, our ratios of earnings to fixed charges, computed using the method outlined by the SEC, were 4.28, 3.47 and 3.39, 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 2016 Form 10-K. At June 30, 2017, our total estimated liability related to environmental sites is $120.8 million. See Note 13 and "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs".

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 2016 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 2016 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 months ended June 30, 2017. See Part II, Item 1A, “Risk Factors” in this report and Part II, Item 7A, “Quantitative and Qualitative Disclosures about Market Risk” in the 2016 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, 2017 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 2016 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 2016 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, 2017:
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
04/01/17-04/30/17	5,168	$ 60.09	—	—
05/01/17-05/31/17	20,840	60.21	—	—
06/01/17-06/30/17	618	62.48	—	—
Total	26,626	60.24	2,124,528	$ 16,732,648

(1) During the quarter ended June 30, 2017, 20,729 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, 5,897 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, 2017, 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, 2018 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, 2017, 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, 2017
/s/ Brody J. Wilson
Brody J. Wilson
Principle Accounting Officer
Vice President, Treasurer, Chief Accounting Officer and Controller

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Quarterly Report on Form 10-Q
For the Quarter Ended June 30, 2017

Exhibit Number	Document
10.1	Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan for Directors (2017).
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, 2017, 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.