NORTHWEST NATURAL GAS CO
Form 10-Q
November 03, 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 September 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 October 27, 2017, 28,713,052 shares of the registrant’s Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended September 30, 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, predicts, 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;
- weather conditions;
- 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 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 September 30,		Nine Months Ended September 30,	
In thousands, except per share data	2017	2016	2017	2016
Operating revenues	$88,190	$87,727	$521,751	$442,439
Operating expenses:				
Cost of gas	27,239	28,264	223,855	157,546
Operations and maintenance	36,867	34,870	115,833	109,771
Environmental remediation	1,355	1,191	10,920	8,113
General taxes	7,901	7,211	24,490	23,333
Depreciation and amortization	21,484	20,628	63,924	61,435
Total operating expenses	94,846	92,164	439,022	360,198
Income (loss) from operations	(6,656)	(4,437)	82,729	82,241
Other income (expense), net	1,493	652	3,332	(1,144)
Interest expense, net	9,451	9,729	29,044	29,183
Income (loss) before income taxes	(14,614)	(13,514)	57,017	51,914
Income tax expense (benefit)	(6,119)	(5,474)	22,473	21,294
Net income (loss)	(8,495)	(8,040)	34,544	30,620
Other comprehensive income (loss):				
Change in employee benefit plan liability, net of tax benefits of $709 for the three and nine months ended September 30, 2016	—	(1,086)	—	(1,086)
Amortization of non-qualified employee benefit plan liability, net of taxes of $98 and $223 for the three months ended and $275 and $477 for the nine months ended September 30, 2017 and 2016, respectively	150	341	423	678
Comprehensive income (loss)	$(8,345)	$(8,785)	$34,967	$30,212
Average common shares outstanding:				
Basic	28,678	27,554	28,653	27,504
Diluted	28,678	27,554	28,734	27,629
Earnings (loss) per share of common stock:				
Basic	$(0.30)	$(0.29)	$1.21	$1.11
Diluted	(0.30)	(0.29)	1.20	1.11
Dividends declared per share of common stock	0.4700	0.4675	1.4100	1.4025

See Notes to Unaudited Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	September 30, 2017	September 30, 2016	December 31, 2016
Assets:			
Current assets:			
Cash and cash equivalents	$15,780	$6,230	$3,521
Accounts receivable	23,450	25,506	66,700
Accrued unbilled revenue	15,974	15,537	64,946
Allowance for uncollectible accounts	(459)	(289)	(1,290)
Regulatory assets	49,504	55,280	42,362
Derivative instruments	2,073	4,857	17,031
Inventories	59,549	67,470	54,129
Gas reserves	16,218	16,257	15,926
Income taxes receivable	—	2,257	—
Other current assets	17,457	17,480	24,728
Total current assets	199,546	210,585	288,053
Non-current assets:			
Property, plant, and equipment	3,384,122	3,177,196	3,208,816
Less: Accumulated depreciation	986,332	943,334	947,916
Total property, plant, and equipment, net	2,397,790	2,233,862	2,260,900
Gas reserves	87,876	103,976	100,184
Regulatory assets	345,352	341,188	357,530
Derivative instruments	1,555	1,151	3,265
Other investments	69,245	67,853	68,376
Other non-current assets	4,243	1,269	1,493
Total non-current assets	2,906,061	2,749,299	2,791,748
Total assets	$3,105,607	$2,959,884	$3,079,801

See Notes to Unaudited Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	September 30, 2017	September 30, 2016	December 31, 2016
Liabilities and equity:			
Current liabilities:			
Short-term debt	$—	$194,900	$53,300
Current maturities of long-term debt	21,995	64,994	39,989
Accounts payable	87,475	55,933	85,664
Taxes accrued	12,295	11,954	12,149
Interest accrued	9,854	9,671	5,966
Regulatory liabilities	34,659	27,921	40,290
Derivative instruments	8,968	5,334	1,315
Other current liabilities	27,705	31,997	35,844
Total current liabilities	202,951	402,704	274,517
Long-term debt	757,429	530,219	679,334
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	572,293	544,575	557,085
Regulatory liabilities	363,838	342,143	349,319
Pension and other postretirement benefit liabilities	212,259	216,909	225,725
Derivative instruments	3,926	1,682	913
Other non-current liabilities	146,229	142,450	142,411
Total deferred credits and other non-current liabilities	1,298,545	1,247,759	1,275,453
Commitments and contingencies (see Note 13 and Note 14)			
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 28,713, 27,558, and 28,630 at September 30, 2017 and 2016, and December 31, 2016, respectively	447,129	389,834	445,187
Retained earnings	406,081	396,938	412,261
Accumulated other comprehensive loss	(6,528)	(7,570)	(6,951)
Total equity	846,682	779,202	850,497
Total liabilities and equity	$3,105,607	$2,959,884	$3,079,801

See Notes to Unaudited Consolidated Financial Statements

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

In thousands	Nine Months Ended September 30, 2017	2016
Operating activities:		
Net income	$34,544	$30,620
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	63,924	61,435
Regulatory amortization of gas reserves	12,036	11,403
Deferred income taxes	17,287	17,810
Qualified defined benefit pension plan expense	3,923	3,989
Contributions to qualified defined benefit pension plans	(15,400)	(11,250)
Deferred environmental expenditures, net	(10,468)	(8,302)
Regulatory disallowance of prior environmental cost deferrals	—	3,287
Amortization of environmental remediation	10,920	8,113
Other	2,605	4,817
Changes in assets and liabilities:		
Receivables, net	90,735	83,377
Inventories	(5,420)	3,226
Income taxes	146	7,170
Accounts payable	(29,726)	(17,612)
Interest accrued	3,888	3,798
Deferred gas costs	13,419	(10,470)
Other, net	443	14,988
Cash provided by operating activities	192,856	206,399
Investing activities:		
Capital expenditures	(145,441)	(98,111)
Other	(1,131)	2,868
Cash used in investing activities	(146,572)	(95,243)
Financing activities:		
Repurchases related to stock-based compensation	(2,034)	(1,042)
Proceeds from stock options exercised	3,711	5,874
Long-term debt issued	100,000	—
Long-term debt retired	(40,000)	—
Change in short-term debt	(53,300)	(75,135)
Cash dividend payments on common stock	(40,390)	(38,556)
Other	(2,012)	(278)
Cash used in financing activities	(34,025)	(109,137)
Increase in cash and cash equivalents	12,259	2,019
Cash and cash equivalents, beginning of period	3,521	4,211
Cash and cash equivalents, end of period	$15,780	$6,230
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalization	$22,859	$23,271
Income taxes paid (refunded)	11,581	(6,900)

See Notes to Unaudited Consolidated Financial Statements

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

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

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

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and 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 nine months ended September 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		
	September 30,		December 31,
In thousands	2017	2016	2016
Current:			
Unrealized loss on derivatives(1)	$8,887	$5,205	$1,315
Gas costs	1,851	10,164	6,830
Environmental costs(2)	6,362	9,734	9,989
Decoupling(3)	15,663	16,028	13,067
Other(4)	16,741	14,149	11,161
Total current	$49,504	$55,280	$42,362
Non-current:			
Unrealized loss on derivatives(1)	$3,926	$1,682	$913
Pension balancing(5)	57,599	48,637	50,863
Income taxes	36,591	40,106	38,670
Pension and other postretirement benefit liabilities	172,687	174,282	183,035
Environmental costs(2)	63,339	64,279	63,970
Gas costs	48	712	89
Decoupling(3)	1,025	1,006	5,860
Other(4)	10,137	10,484	14,130
Total non-current	$345,352	$341,188	$357,530

	Regulatory Liabilities		
	September 30,		December 31,
In thousands	2017	2016	2016
Current:			
Gas costs	$16,459	$12,001	$8,054
Unrealized gain on derivatives(1)	2,020	4,857	16,624
Decoupling(3)	314	—	—
Other(4)	15,866	11,063	15,612
Total current	$34,659	$27,921	$40,290
Non-current:			
Gas costs	$1,015	$765	$1,021
Unrealized gain on derivatives(1)	1,555	1,151	3,265
Accrued asset removal costs(6)	356,106	336,699	341,107
Other(4)	5,162	3,528	3,926
Total non-current	$363,838	$342,143	$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

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periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility’s authorized rate of return, with the equity portion of interest income recognized when amounts are collected in rates.
(6) Estimated costs of removal on certain regulated properties are collected through rates.

We believe all costs incurred and deferred at September 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 nine months ended September 30, 2017.

Recently Issued Accounting Pronouncements
DERIVATIVES AND HEDGING. On August 28, 2017, the FASB issued ASU 2017-12, "Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities." The purpose of the amendment is to more closely align hedge accounting with companies’ risk management strategies. The ASU amends the accounting for risk component hedging, the hedged item in fair value hedges of interest rate risk, and amounts excluded from the assessment of hedge effectiveness. The guidance also amends the recognition and presentation of the effect of hedging instruments and includes other simplifications of hedge accounting. The amendments in this update are effective for us beginning January 1, 2019. Early adoption is permitted. The amended presentation and disclosure guidance is required prospectively. We are currently assessing the effect of this standard on our financial statements and disclosures.

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. 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. Only the service cost component of the net periodic benefit cost is eligible for capitalization. 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. During the third quarter 2017, the FERC indicated that it will allow entities to change their capitalization policy for regulatory accounting and reporting purposes to be consistent with the new US GAAP requirements. This change will be allowed as a one-time policy election upon adoption of the guidance. We are currently evaluating whether or not to adopt the new ASU for FERC regulatory accounting and reporting purposes and assessing the effect of this standard on our financial statements and disclosures.

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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 herein and 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 and do not believe the standard will have a material impact on our financial position, net income or cash flows. 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.

Accounting Policies
Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. See Note 14.

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3. EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share data	2017	2016	2017	2016
Net income (loss)	$(8,495)	$(8,040)	$34,544	$30,620
Average common shares outstanding - basic	28,678	27,554	28,653	27,504
Additional shares for stock-based compensation plans (See Note 5)	—	—	81	125
Average common shares outstanding - diluted	28,678	27,554	28,734	27,629
Earnings (loss) per share of common stock - basic	$(0.30)	$(0.29)	$1.21	$1.11
Earnings (loss) per share of common stock - diluted	$(0.30)	$(0.29)	$1.20	$1.11
Additional information:				
Antidilutive shares	96	159	15	5

4. SEGMENT INFORMATION

We primarily operate in two reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which are aggregated and reported as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes the utility portion of our Mist underground storage facility 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 September 30,			
In thousands	Utility	Gas Storage	Other	Total
2017				
Operating revenues	$81,126	$7,006	$58	$88,190
Depreciation and amortization	20,023	1,461	—	21,484
Income (loss) from operations	(9,977)	3,543	(222)	(6,656)
Net income (loss)	(10,349)	1,899	(45)	(8,495)

Capital expenditures	50,009	164	950	51,123
2016				
Operating revenues	$80,378	$7,293	$56	$87,727
Depreciation and amortization	19,173	1,455	—	20,628
Income (loss) from operations	(7,264)	3,502	(675)	(4,437)
Net income (loss)	(9,511)	1,813	(342)	(8,040)
Capital expenditures	36,238	437	—	36,675

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	Nine Months Ended September 30,			
In thousands	Utility	Gas Storage	Other	Total
2017				
Operating revenues	$503,947	$17,635	$169	$521,751
Depreciation and amortization	59,541	4,383	—	63,924
Income (loss) from operations	77,706	5,748	(725)	82,729
Net income (loss)	31,980	2,716	(152)	34,544
Capital expenditures	143,128	1,363	950	145,441
Total assets at September 30, 2017	2,835,860	252,041	17,706	3,105,607
2016				
Operating revenues	$422,617	$19,654	$168	$442,439
Depreciation and amortization	56,894	4,541	—	61,435
Income from operations	74,745	8,107	(611)	82,241
Net income	26,848	3,988	(216)	30,620
Capital expenditures	96,710	1,401	—	98,111
Total assets at September 30, 2016	2,684,618	259,483	15,783	2,959,884
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 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 September 30,		Nine Months Ended September 30,	
In thousands	2017	2016	2017	2016
Utility margin calculation:				
Utility operating revenues [1]	$81,126	$80,378	$503,947	$422,617
Less: Utility cost of gas	27,239	28,264	223,855	157,546
Environmental remediation expense	1,355	1,191	10,920	8,113
Utility margin	$52,532	$50,923	$269,172	$256,958

(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.

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Long Term Incentive Plan

Performance Shares

LTIP performance shares incorporate a combination of market, performance, and service-based factors. During the nine months ended September 30, 2017, 34,340 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 nine months ended September 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 September 30, 2017, there was $2.5 million of unrecognized compensation cost from LTIP grants, which is expected to be recognized through 2019.

Restricted Stock Units

During the nine months ended September 30, 2017, 32,168 RSUs were granted under the LTIP with a weighted-average grant date fair value of $60.51 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 an RSU is equal to the closing market price of our common stock on the grant date. As of September 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 2022.

6. DEBT

Short-Term Debt

At September 30, 2017, we had no outstanding short-term debt.

Long-Term Debt

At September 30, 2017, we had long-term debt of $779.4 million, which included $7.3 million of unamortized debt issuance costs. Utility long-term debt consists of first mortgage bonds (FMBs) with maturity dates ranging from 2018 through 2047, interest rates ranging from 1.545% to 9.05%, and a weighted-average coupon rate of 4.780%. In August 2017, we retired $40 million of FMBs with a coupon rate of 7.00%, and in September 2017, we issued $100 million of FMBs. The FMBs issued in September 2017, consisted of $25 million at 2.822%, due in 2027 and $75 million at 3.685%, due in 2047.

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.

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

	September 30,		December 31,
In thousands	2017	2016	2016
Gross long-term debt	$786,700	$601,700	$726,700
Unamortized debt issuance costs	(7,276)	(6,487)	(7,377)
Carrying amount	$779,424	$595,213	$719,323
Estimated fair value(1)	$847,068	$701,183	$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 September 30,				Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
In thousands	2017	2016	2017	2016	2017	2016	2017	2016
Service cost	$1,881	$1,978	$98	$119	$5,621	$5,866	$295	$361
Interest cost	4,484	4,607	274	301	13,428	13,755	822	901
Expected return on plan assets	(5,112)	(5,017)	—	—	(15,337)	(15,051)	—	—
Amortization of prior service costs	32	57	(117)	(117)	95	173	(351)	(351)
Amortization of net actuarial loss	3,656	3,555	138	192	10,899	10,559	415	575
Settlement expense	—	193	—	—	—	193	—	—
Net periodic benefit cost	4,941	5,373	393	495	14,706	15,495	1,181	1,486
Amount allocated to construction	(1,581)	(1,556)	(136)	(163)	(4,660)	(4,678)	(403)	(491)
Amount deferred to regulatory balancing account(1)	(1,484)	(1,542)	—	—	(4,519)	(4,762)	—	—
Net amount charged to expense	$1,876	$2,275	$257	$332	$5,527	$6,055	$778	$995

(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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2017	2016	2017	2016
Beginning balance	$(6,678)	$(6,825)	$(6,951)	$(7,162)

Amounts reclassified to AOCL	—	(1,795)	—	(1,795)
Amounts reclassified from AOCL:				
Amortization of actuarial losses	248	371	698	962
Loss from plan settlement	—	193	—	193
Total reclassifications before tax	248	(1,231)	698	(640)
Tax (benefit) expense	(98)	486	(275)	232
Total reclassifications for the period	150	(745)	423	(408)
Ending balance	$(6,528)	$(7,570)	$(6,528)	$(7,570)

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Employer Contributions to Company-Sponsored Defined Benefit Pension Plans
For the nine months ended September 30, 2017, we made cash contributions totaling $15.4 million to our qualified defined benefit pension plans. We expect further plan contributions of $4.0 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 $4.1 million and $3.6 million for the nine months ended September 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 September 30,		Nine Months Ended September 30,	
Dollars in thousands	2017	2016	2017	2016
Income taxes at statutory rates (federal and state)	$(5,838)	$(5,339)	$22,487	$20,620
Increase (decrease):				
Differences required to be flowed-through by regulatory commissions	(302)	(381)	1,282	1,202
Other, net	21	246	(1,296)	(528)
Total provision for income taxes	$(6,119)	$(5,474)	$22,473	$21,294
Effective tax rate	41.9 %	40.5 %	39.4 %	41.0 %

The effective income tax rate for the three months ended September 30, 2017 compared to the same period in 2016 increased primarily as a result of increased stock-based compensation deductions in 2017. The effective income tax rate for the nine months ended September 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:

	September 30,		December 31,
In thousands	2017	2016	2016
Utility plant in service	$2,934,424	$2,815,340	$2,843,243
Utility construction work in progress	145,148	58,470	62,264
Less: Accumulated depreciation	937,498	899,851	903,096
Utility plant, net	2,142,074	1,973,959	2,002,411
Non-utility plant in service	300,224	298,586	299,378
Non-utility construction work in progress	4,326	4,800	3,931
Less: Accumulated depreciation	48,834	43,483	44,820
Non-utility plant, net	255,716	259,903	258,489
Total property, plant, and equipment	$2,397,790	$2,233,862	$2,260,900
Capital expenditures in accrued liabilities	$41,732	$8,918	$9,547

10. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of September 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:

	September 30,		December 31,
In thousands	2017	2016	2016
Gas reserves, current	$16,218	$16,257	$ 15,926
Gas reserves, non-current	171,318	171,280	171,610
Less: Accumulated amortization	83,442	67,304	71,426
Total gas reserves[(1)]	104,094	120,233	116,110
Less: Deferred taxes on gas reserves	29,298	25,799	28,119

Net investment in gas reserves	$74,796	$94,434	$ 87,991

(1) Our net investment in additional wells included in total gas reserves was $6.0 million, $7.0 million and $6.7 million at September 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 September 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:

	September 30,	December

In thousands	2017	2016	31, 2016
Natural gas (in therms):			
Financial	521,080	537,100	477,430
Physical	750,650	621,230	535,450
Foreign exchange	$6,933	$8,404	$ 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 September 30,			
	2017		2016	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$(2,566)	$ 51	$(8,045)	$ (52)
Operating gain (loss)	28	—	(110)	—
Amounts deferred to regulatory accounts on balance sheet	2,548	(51)	8,118	52
Total gain (loss) in pre-tax earnings	$10	$ —	$(37)	$ —

	Nine Months Ended September 30,			
	2017		2016	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$(19,081)	$ 275	$5,562	$ 5
Operating loss	(1,249)	—	(266)	—
Amounts deferred to regulatory accounts on balance sheet	19,895	(275)	(5,385)	(5)
Total loss in pre-tax earnings	$(435)	$ —	$(89)	$ —

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 $1.0 million for the three and nine months ended September 30, 2017 from the settlement of natural gas financial derivative contracts. Whereas, we realized net losses of $1.0 million and $24.1 million for the three and nine months ended September 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 September 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 $12.0 million at September 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	$ —	$ —	$ —	$ (3,138)	$ (9,146)
Without Adequate Assurance Calls	—	—	—	(3,138)	(7,113)

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 $3.3 million and a liability of $12.6 million as of September 30, 2017. As of September 30, 2016, our derivative position would have resulted in an asset of $4.1 million and a liability of $5.1 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 September 30, 2017. As of September 30, 2017 and 2016, and December 31, 2016, the net fair value was a liability of $9.3 million, a liability of $1.0 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 nine months ended September 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

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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. Refer to "Other Portland Harbor" below.

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		
	September 30,		December 31,	September 30,		December 31,
In thousands	2017	2016	2016	2017	2016	2016
Portland Harbor site:						
Gasco/Siltronic Sediments	$860	$1,726	$ 869	$43,796	$42,880	$43,972
Other Portland Harbor	1,379	1,461	1,970	3,618	4,362	4,148
Gasco/Siltronic Upland site	7,537	8,191	10,657	48,758	49,928	49,183
Central Service Center site	31	112	73	—	—	—
Front Street site	846	841	906	10,788	7,818	7,786
Oregon Steel Mills	—	—	—	179	179	179
Total	$10,653	$12,331	$ 14,475	$107,139	$105,167	$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 with the other PRPs 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.

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 $44.7 million to $350 million. We have recorded a liability of $44.7 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 the Gasco/Siltronic sediments site represent our largest exposure, we do have other potential exposures associated with the Portland Harbor ROD, including NRD costs and harborwide clean-up costs (including downstream petroleum contamination), for which the allocations among the PRPs 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, and filed a second amended complaint on August 18, 2017. We have recorded a liability for NRD 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 aforementioned 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, 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, excluding the uplands for Siltronic. 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.

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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 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

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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 September 30, 2017, we have applied $63.2 million of insurance proceeds to prudently incurred remediation costs.

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

	September 30,		December 31,
In thousands	2017	2016	2016
Deferred costs and interest [1]	$52,888	$54,704	$53,039
Accrued site liabilities [2]	117,388	117,202	119,443
Insurance proceeds and interest	(100,575)	(97,893)	(98,523)
Total regulatory asset deferral[1]	$69,701	$74,013	$73,959
Current regulatory assets[3]	6,362	9,734	9,989
Long-term regulatory assets[3]	63,339	64,279	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

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

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

14. SUBSEQUENT EVENT

On October 9, 2017, the Company entered into a 20-year operating lease agreement for our new headquarters location in Portland, Oregon, in anticipation of the expiration of our current headquarters lease. The new lease payments are expected to commence in 2020 upon the expiration of our current headquarters lease, and total estimated base rent payments over the life of the lease are approximately $160 million. The Company has the option to extend the term of the new lease for two additional seven-year periods.

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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 September 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. Current operational highlights include:

- awarded the highest customer satisfaction score among large gas utilities in the West for the fifth year in a row in the 2017 J.D. Power and Associates study;
- reduced residential customer rates for the third consecutive year resulting in a cumulative decrease of 15% in Oregon and 18% in Washington over that time;
- added nearly 12,700 customers during the past twelve months for a growth rate of 1.8% at September 30, 2017;
- invested $145 million in our distribution system and facilities for growth and reliability;
- continued construction on our North Mist Gas Storage Expansion Project, with $72 million of capital expenditures incurred as of September 30, 2017; and
- delivered increasing dividends for the 62nd consecutive year. Our current annual indicated dividend rate is $1.89 per share.

Key financial highlights include:

	Three Months Ended September 30,				
	2017		2016		$
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net loss	$(8,495)	$(0.30)	$(8,040)	$(0.29)	$(455)
Utility margin	52,532		50,923		1,609
Gas storage operating revenues	7,006		7,293		(287)

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Consolidated net loss increased $0.5 million primarily due to the following factors:

- a $2.0 million increase in operating and maintenance expense largely from utility payroll and benefits increases, as well as increased safety equipment upgrade costs; partially offset by
- a $1.6 million increase in utility margin primarily due to customer growth.

	Nine Months Ended September 30,				
	2017		2016		$
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net income	$34,544	$1.20	$30,620	$1.11	$3,924
Adjustments:					
Regulatory environmental disallowance, net of taxes ($1.3 million for 2016)[1]	—	—	1,996	0.07	(1,996)
Adjusted consolidated net income[1]	$34,544	$1.20	$32,616	$1.18	$1,928
Utility margin	$269,172		$256,958		$12,214
Gas storage operating revenues	17,635		19,654		(2,019)

[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 27.6 million diluted shares for the nine months ended September 30, 2016.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Consolidated net income increased $3.9 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 $1.9 million primarily due to the following factors:

- a $12.2 million increase in utility margin primarily due to customer growth and the effects of colder than average weather in 2017 compared to warmer than average weather in the prior period; partially offset by
- a $6.6 million increase in operating and maintenance expense largely from higher utility payroll and benefits increases, as well as increased safety equipment upgrade costs; and
- a $2.0 million decrease in gas storage revenues largely due to lower revenues from our asset management agreements for our Mist storage and transportation capacity.

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DIVIDENDS

Dividend highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,			
Per common share	2017	2016	2017	2016	QTR Change	YTD Change
Dividends paid	$0.4700	$0.4675	$1.4100	$1.4025	$0.0025	$0.0075

In October 2017, the Board of Directors declared a quarterly dividend on our common stock of $0.4725 cents per share, payable on November 15, 2017, to shareholders of record on October 31, 2017, reflecting an annual indicated dividend rate of $1.89 per share.

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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 early 2018 and filing a Washington rate case thereafter.

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

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. The second phase examined potential hedging guidelines for gas utilities. We continue to work with the parties in this proceeding to determine an appropriate resolution of this docket. We anticipate resolution of the docket in 2017 or early 2018.

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. As directed by the WUTC, we submitted our preliminary hedging plan with our 2017 PGA in September 2017, and plan to submit our annual comprehensive hedging plan with our 2018 PGA.

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 2017.

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. In September 2017, the parties to the docket filed a settlement with the Commission requesting approval of updated depreciation rates negotiated with the parties. The depreciation rates included in the stipulation do not materially change our current depreciation rates. We anticipate a resolution of the docket in 2017.

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 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, to continue the settlement process. 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, and expect resolutions by the end of the first quarter of 2018. 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.

As of September 30, 2017, in addition to the amount hedged for the 2016-17 gas year, we are also hedged in future gas years at approximately 70% for the 2017-18 gas year and between 4% and 23% for annual requirements over the subsequent five gas years. 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.

In September 2017, we filed our PGA and received OPUC and WUTC approval in October 2017. PGA rate changes are effective November 1, 2017. The rate changes will decrease the average monthly bills of residential customers by approximately 6.4% and 3.1% in Oregon and Washington, respectively. The decrease in Oregon reflected customers' portion of adjustments mainly for changes in wholesale natural gas costs and for a portion of WARM amounts that exceeded the maximum monthly allowable amount to be returned to customers during the 2016-17 gas year. Oregon rates were offset by adjustments related to our energy efficiency programs and additional annual adjustments based on ongoing orders with the OPUC. Washington rates reflected changes in wholesale natural gas costs.

Each year, we typically hedge gas prices on a portion of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2017-18 gas year (November 1, 2017 - October 31, 2018) and the 2016-17 gas year (November 1, 2016 - October 31, 2017) hedged near 75% of our forecasted sales volumes, including 49% and 48% in financial swap and option contracts as well as 26% and 27% in physical gas supplies, respectively. 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.

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 2017-18 and 2016-17 gas years, we selected the 90% deferral option. 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. See "Regulatory Proceeding Updates—Hedging" above.

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. Volumes produced from additional wells drilled after our amended agreement are included in our Oregon PGA at a fixed rate of $0.4725. We did not have the opportunity to participate in additional wells during 2015, 2016, or the nine months ended September 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 due to tariff caps and floors 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 September 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.

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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. We anticipate the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate. We included $7.4 million and $10.0 million of deferred remediation expense approved by the OPUC for collection during the 2017-18 and 2016-17 PGA years, respectively.

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. The submission was approved in July 2017, with no earnings test adjustment.

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

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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 $4.5 million and $4.8 million during the nine months ended September 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 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 September 30,		Nine Months Ended September 30,			
Dollars and therms in thousands, except EPS data	2017	2016	2017	2016	QTR Change	YTD Change
Utility net income (loss)	$(10,349)	$(9,511)	$31,980	$26,848	$(838)	$5,132
EPS - utility segment	$(0.36)	$(0.35)	$1.11	$0.97	$(0.01)	$0.14
Gas sold and delivered (in therms)	163,621	162,205	865,903	727,687	1,416	138,216
Utility margin[1]	$52,532	$50,923	$269,172	$256,958	$1,609	$12,214

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

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. The primary factors contributing to the $0.8 million or $0.01 per share increase in utility net loss were as follows:

- 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, as well as increased safety equipment upgrade costs; partially offset by
- a $1.6 million increase in utility margin primarily due to customer growth.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. The primary factors contributing to the $5.1 million or $0.14 per share increase in utility net income were as follows:

- a $12.2 million increase in utility margin primarily due to:
  - a $5.0 million increase from customer growth; partially 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 warmer than average weather in the prior period.
- a $3.9 million increase in other income (expense), net, primarily due to the environmental interest disallowance recognized in 2016 and increased earnings from the equity portion of AFUDC in 2017; partially offset by

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- a $5.7 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 increased safety equipment upgrade costs; and
- a $2.6 million increase in depreciation expense primarily due to additional capital expenditures.

Total utility volumes sold and delivered in the three months ended September 30, 2017 increased 1% over the same period in 2016. For the nine months ended September 30, 2017, total utility volumes sold and delivered increased 19% due to the impact of weather that was 42% colder than the prior period and 11% colder than average for the nine months ended September 30, 2017.

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

In thousands, except degree day and customer data	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	Favorable/(Unfavorable) QTD Change	Favorable/(Unfavorable) YTD Change
Utility volumes (therms):						
Residential and commercial sales	54,557	55,610	495,949	381,109	(1,053)	114,840
Industrial sales and transportation	109,064	106,595	369,954	346,578	2,469	23,376
Total utility volumes sold and delivered	163,621	162,205	865,903	727,687	1,416	138,216
Utility operating revenues:						
Residential and commercial sales	$69,294	$68,508	$466,867	$388,689	$786	$78,178
Industrial sales and transportation	13,488	13,412	47,182	42,048	76	5,134
Other revenues	606	619	3,149	3,132	(13)	17
Less: Revenue taxes	2,262	2,161	13,251	11,252	(101)	(1,999)
Total utility operating revenues	81,126	80,378	503,947	422,617	748	81,330
Less: Cost of gas	27,239	28,264	223,855	157,546	1,025	(66,309)
Less: Environmental remediation expense	1,355	1,191	10,920	8,113	(164)	(2,807)
Utility margin	$52,532	$50,923	$269,172	$256,958	$1,609	$12,214
Utility margin:[1]						
Residential and commercial sales	$44,612	$43,050	$241,617	$227,422	$1,562	$14,195
Industrial sales and transportation	7,272	7,173	23,529	22,458	99	1,071
Miscellaneous revenues	606	616	3,144	3,119	(10)	25
Gain from gas cost incentive sharing	102	85	940	4,151	17	(3,211)
Other margin adjustments	(60)	(1)	(58)	(192)	(59)	134
Utility margin	$52,532	$50,923	$269,172	$256,958	$1,609	$12,214
Degree days						
Average[2]	95	95	2,641	2,657	—	(16)
Actual	78	78	2,931	2,066	— %	42 %
Percent colder (warmer) than average weather[2]	(18)%	(18)%	11 %	(22)%		

Customers - end of period:	As of September 30, 2017	2016	Change
Residential customers	662,555	650,950	11,605
Commercial customers	67,248	66,174	1,074
Industrial customers	1,021	1,015	6
Total number of customers	730,824	718,139	12,685
Customer growth (12 month rolling):			
Residential customers	1.8 %		
Commercial customers	1.6 %		
Industrial customers	0.6 %		
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 September 30, 2017	2016	Nine Months Ended September 30, 2017	2016	QTR Change	YTD Change
Volumes (therms):						
Residential sales	29,308	29,820	307,655	232,121	(512)	75,534
Commercial sales	25,249	25,790	188,294	148,988	(541)	39,306
Total volumes	54,557	55,610	495,949	381,109	(1,053)	114,840
Operating revenues:						
Residential sales	$43,290	$43,102	$308,416	$257,401	$188	$51,015
Commercial sales	26,004	25,406	158,451	131,288	598	27,163
Total operating revenues	$69,294	$68,508	$466,867	$388,689	$786	$78,178
Utility margin:						
Residential:						
Sales	$28,628	$27,943	$178,998	$145,033	$685	$33,965
Weather normalization	1	—	(11,779)	13,966	1	(25,745)
Decoupling	1,187	1,325	54	(834)	(138)	888
Total residential utility margin	29,816	29,268	167,273	158,165	548	9,108
Commercial:						
Sales	12,593	12,472	70,824	58,370	121	12,454
Weather normalization	—	—	(4,511)	5,483	—	(9,994)
Decoupling	2,203	1,310	8,031	5,404	893	2,627
Total commercial utility margin	14,796	13,782	74,344	69,257	1,014	5,087
Total utility margin	$44,612	$43,050	$241,617	$227,422	$1,562	$14,195

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. The primary factors contributing to changes in the residential and commercial markets were increases of $0.8 million in operating revenues and $1.6 million in utility margin due to customer growth, slightly offset by a decrease in sales volumes of 1.1 million therms, or 2%.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. The primary factors contributing to changes in the residential and commercial markets were increases of $78.2 million in operating revenue and $14.2 million in utility margin as a result of sales volume increases of 114.8 million therms, or 30%, 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 September 30, 2017	2016	Nine Months Ended September 30, 2017	2016	QTR Change	YTD Change
Volumes (therms):						
Industrial - firm sales	7,870	7,817	25,883	24,363	53	1,520
Industrial - firm transportation	33,826	32,737	121,452	112,456	1,089	8,996
Industrial - interruptible sales	10,207	9,902	40,388	36,274	305	4,114
Industrial - interruptible transportation	57,161	56,139	182,231	173,485	1,022	8,746
Total volumes	109,064	106,595	369,954	346,578	2,469	23,376
Utility margin:						
Industrial - firm and interruptible sales	$ 2,755	$ 2,703	$ 8,870	$ 8,479	$ 52	$ 391
Industrial - firm and interruptible transportation	4,517	4,470	14,659	13,979	47	680
Industrial - sales and transportation	$ 7,272	$ 7,173	$ 23,529	$ 22,458	$ 99	$ 1,071

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Sales and transportation volumes increased by 2.5 million therms and utility margin increased by $0.1 million.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Sales and transportation volumes increased by 23.4 million therms and utility margin increased by $1.1 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 September 30, 2017	2016	Nine Months Ended September 30, 2017	2016

					QTR Change	YTD Change
Cost of gas	$27,239	$28,264	$223,855	$157,546	$(1,025)	$66,309
Volumes sold (therms)[1]	72,634	73,329	562,220	441,746	(695)	120,474
Average cost of gas (cents per therm)	$0.38	$0.39	$0.40	$0.36	$(0.01)	$0.04
Gain from gas cost incentive sharing[2]	$102	$85	$940	$4,151	$17	$(3,211)

(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.

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Cost of gas decreased $1.0 million reflecting a 1% decrease in volumes and a 3% decrease in average cost of gas due to lower natural gas prices.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Cost of gas increased $66.3 million, or 42%, primarily due to a 27% increase in volumes sold due to colder than average weather in 2017 compared to warmer than average weather in the prior period, customer growth, and an 11% increase in average cost of gas as cost of gas in 2016 includes an offset of $19.4 million from the gas cost savings credited to customers.

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 September 30,		Nine Months Ended September 30,			
In thousands, except EPS data	2017	2016	2017	2016	QTR Change	YTD Change
Operating revenues	$7,006	$7,293	$17,635	$19,654	$(287)	$(2,019)
Operating expenses	3,463	3,791	11,887	11,547	(328)	340
Gas storage net income	1,899	1,813	2,716	3,988	86	(1,272)
EPS - gas storage segment	0.06	0.06	0.09	0.14	—	(0.05)

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Our gas storage segment net income increased $0.1 million.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Our gas storage segment net income decreased $1.3 million or $0.05 per share primarily due to the following factors:

- a $2.0 million decrease in gas storage revenues largely due to lower revenues from our asset management agreements for our Mist storage and transportation capacity; and
- a $0.3 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 summer/winter natural gas price spreads, gas price volatility, and gas storage values, but there can be no assurance that this will result.

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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 $193.0 million at September 30, 2017. We continue to assess these conditions and their impact on net book value on an ongoing basis, as well as all current and future strategic alternatives with respect to the Gill Ranch gas storage facility. 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 nine months ended September 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 September 30,		Nine Months Ended September 30,			
In thousands	2017	2016	2017	2016	QTR Change	YTD Change
Operations and maintenance	$36,867	$34,870	$115,833	$109,771	$ 1,997	$ 6,062

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Operations and maintenance expense increased $2.0 million reflecting higher utility payroll and benefits due to increased headcount, general salary increases as well as increased safety equipment upgrade costs.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Operations and maintenance expense increased $6.1 million reflecting higher utility payroll and benefits due to increased headcount, general salary increases, and higher health care costs, as well as increased safety equipment upgrade costs and 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 nine months ended September 30, 2017 and 2016.

Other Income (Expense), Net

Other income (expense), net highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,			
In thousands	2017	2016	2017	2016	QTR Change	YTD Change
Other income (expense), net	$1,493	$652	$3,332	$(1,144)	$ 841	$4,476

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Other income (expense), net, increased $0.8 million primarily due to increased earnings of $0.7 million from the equity portion of AFUDC.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Other income (expense), net, increased $4.5 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 from increased earnings of $1.5 million from the equity portion of AFUDC.

Interest Expense, Net

Interest expense, net highlights include:

	Three Months Ended September 30,		Nine Months Ended September 30,			
In thousands	2017	2016	2017	2016	QTR Change	YTD Change
Interest expense, net	$9,451	$9,729	$29,044	$29,183	$(278)	$(139)

THREE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Interest expense, net decreased $0.3 million primarily due to a $0.6 million increase in benefits recognized from the interest-related portion of AFUDC, partially offset by increased interest expense of $0.3 million due to the issuance of long-term debt in December 2016.

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED TO SEPTEMBER 30, 2016. Interest expense, net decreased $0.1 million primarily due to a $1.3 million increase in benefits recognized from the interest-related portion of AFUDC, partially offset by increased interest expense of $1.2 million due to the issuance of long-term debt in December 2016.

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.

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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:

	September 30,		December 31,
	2017	2016	2016
Common stock equity	52.1 %	49.6 %	52.4 %
Long-term debt	46.6	33.8	41.9
Short-term debt, including current maturities of long-term debt	1.3	16.6	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 September 30, 2017 we had $15.8 million of cash and cash equivalents compared to $6.2 million at September 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 September 30, 2017, we have Board authorization to issue up to $75 million of additional FMBs. We also have OPUC approval to issue up to $75 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 September 30, 2017. However, if the credit risk-related contingent features underlying these contracts were triggered on September 30, 2017, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $9.1 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

On October 9, 2017, the Company entered into a 20-year operating lease agreement for our new headquarters location in Portland, Oregon. The Company's existing headquarters lease expires in 2020 and after an extensive search and evaluation process with a focus on seismic preparedness, safety, reliability, least cost to our rate payers and a continued commitment to our employees and the communities we serve, we executed a new lease for suitable commercial office space in Portland, Oregon. Payments under the lease are expected to commence in 2020 and total estimated base rent payments over the life of the lease are approximately $160 million. The Company has the option to extend the term of the lease for two additional seven-year periods.

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. When we have outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, it is supported by one or more unsecured revolving credit facilities. See “Credit Agreements” below.

At September 30, 2017, our utility had no short-term debt outstanding compared to $194.9 million at September 30, 2016 due to lower working capital needs and net proceeds from our equity issuance in November 2016 and issuances of long-term debt instruments in December 2016 and September 2017. The effective interest rate on short-term debt outstanding at September 30, 2016 was 0.7%.

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 September 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 September 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 September 30, 2017 and 2016, with consolidated indebtedness to total capitalization ratios of 47.9% and 50.3%, 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 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.

Long-Term Debt

We retired $40 million of FMBs with a coupon rate of 7.00% in August 2017 and issued $25 million and $75 million of FMBs with coupon rates of 2.822% and 3.685%, respectively, in September 2017. No other debt was retired or issued in the nine months ended September 30, 2017. Over the next twelve months, $22 million of FMBs with a coupon rate of 6.60% will mature in March 2018.

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:

Nine Months Ended
September 30,

In thousands	2017	2016	YTD Change
Cash provided by operating activities	$192,856	$206,399	$(13,543)

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED to SEPTEMBER 30, 2016. The significant factors contributing to the $13.5 million decrease in cash flows provided by operating activities were as follows:

- a decrease of $16.0 million from changes in tax-related accounts primarily due to a refund of federal income tax overpayments received in 2016 and additional cash flow benefits reflected in the prior period related to the enactment of bonus depreciation in December 2015; and

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- a net decrease of $13.4 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; partially offset by
- an increase of $23.9 million in cash flow benefits from changes in deferred gas cost balances primarily due to the $19.4 million gas cost savings credited to customers in 2016 that did not occur in 2017.

The non-cash qualified defined benefit pension expense recognized on the income statement for the nine months ended September 30, 2017 and 2016 was $3.9 million and $4.0 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 nine months ended September 30, 2017, we contributed $15.4 million to our utility's qualified defined benefit pension plan, compared to $11.3 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 Note 14 herein as well as "Financial Condition—Contractual Obligations" and Note 14 in the 2016 Form 10-K.

Investing Activities

Investing activity highlights include:

In thousands	Nine Months Ended September 30, 2017	2016	YTD Change
Total cash used in investing activities	$(146,572)	$(95,243)	$(51,329)
Capital expenditures	(145,441)	(98,111)	(47,330)

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED to SEPTEMBER 30, 2016. The $51.3 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. When the expansion is placed into service, the investment will immediately be included in rate base under an established tariff schedule already approved by the OPUC, with revenues recognized consistent with the schedule. 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.

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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:

	Nine Months Ended September 30,		
In thousands	2017	2016	YTD Change
Total cash used in financing activities	$(34,025)	$(109,137)	$75,112
Change in short-term debt	(53,300)	(75,135)	21,835
Change in long-term debt	60,000	—	60,000

NINE MONTHS ENDED SEPTEMBER 30, 2017 COMPARED to SEPTEMBER 30, 2016. The $75.1 million decrease in cash used in financing activities was primarily due to $100 million of proceeds from long-term debt issued in September 2017, as well as lower repayments of $21.8 million of short-term debt compared to the prior period, partially offset by a $40.0 million repayment of long-term debt in August 2017.

Ratios of Earnings to Fixed Charges

For the nine and twelve months ended September 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 2.67, 3.34 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 September 30, 2017, our total estimated liability related to environmental sites is $117.8 million. See Note 13 and "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs".

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APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements in accordance with GAAP, management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions. Our most critical estimates and judgments include accounting for:

- regulatory accounting;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes;
- environmental contingencies; and
- impairment of long-lived assets.

There have been no material changes to the information provided in the 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 nine months ended September 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 September 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 September 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
07/01/17-07/31/17	738	$ 59.98	—	—
08/01/17-08/31/17	15,023	64.82	—	—
09/01/17-09/30/17	562	66.32	—	—
Total	16,323	64.65	2,124,528	$ 16,732,648

(1) During the quarter ended September 30, 2017, 14,557 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 1,766 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended September 30, 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 September 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 below.

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

Exhibit Number	Document
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.	The following materials from Northwest Natural Gas Company's Quarterly Report on Form 10-Q for the quarter ended September 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.

SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)
Dated: November 3, 2017

/s/ Brody J. Wilson
Brody J. Wilson
Principal Accounting Officer
Vice President, Treasurer, Chief Accounting Officer and Controller