NORTHWEST NATURAL GAS CO
Form 10-Q
May 08, 2018

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 March 31, 2018

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 April 27, 2018, 28,783,697 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended March 31, 2018

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION
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, believes, estimates, expects, and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans, projections and predictions;
- objectives, goals or strategies;
- assumptions, generalizations and estimates;
- ongoing continuation of past practices or patterns;
- future events or performance;
- trends;
- risks;
- timing and cyclicality;
- earnings and dividends;
- capital expenditures and allocation;
- capital or organizational structure, including restructuring as a holding company;
- climate change and our role in a low-carbon future;
- growth;
- customer rates;
- labor relations and workforce succession;
- commodity costs;
- gas reserves;
- operational performance and costs;
- energy policy, infrastructure and preferences;
- public policy approach and involvement;
- efficacy of derivatives and hedges;
- liquidity, financial positions, and planned securities issuances;
- valuations;
- project and program development, expansion, or investment;
- business development efforts, including acquisitions and integration thereof;
- pipeline capacity, demand, location, and reliability;
- adequacy of property rights and headquarter development;
- technology implementation and cybersecurity practices;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- rate or regulatory outcomes, recovery or refunds;
- impacts or changes of laws, rules and regulations;
- tax liabilities or refunds, including effects of tax reform;
- 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, expectations and treatment with respect to retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- effects of new or anticipated changes in critical accounting policies or estimates;
- approval and adequacy of regulatory deferrals;

- effects and efficacy of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs and recoveries, and timing thereof.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future operational or financial performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2017 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", respectively of Part II of this report.

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

Table of Contents

undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

Table of Contents

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

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

In thousands, except per share data	Three Months Ended March 31, 2018	2017
Operating revenues	$264,712	$297,323
Operating expenses:		
Cost of gas	108,106	143,611
Operations and maintenance	40,559	39,116
Environmental remediation	4,624	6,954
General taxes	9,808	9,025
Revenue taxes	12,429	—
Depreciation and amortization	20,985	21,085
Other operating expenses	853	—
Total operating expenses	197,364	219,791
Income from operations	67,348	77,532
Other income (expense), net	(834)	(423)
Interest expense, net	9,515	9,876
Income before income taxes	56,999	67,233
Income tax expense	15,462	26,923
Net income	41,537	40,310
Other comprehensive income:		
Amortization of non-qualified employee benefit plan liability, net of taxes of $55 and $89 for the three months ended March 31, 2018 and 2017, respectively	154	136
Comprehensive income	$41,691	$40,446
Average common shares outstanding:		
Basic	28,753	28,633
Diluted	28,803	28,723
Earnings per share of common stock:		
Basic	$1.44	$1.41
Diluted	1.44	1.40
Dividends declared per share of common stock	0.4725	0.4700

See Notes to Unaudited Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	March 31, 2018	March 31, 2017	December 31, 2017
Assets:			
Current assets:			
Cash and cash equivalents	$11,215	$40,639	$3,472
Accounts receivable	78,091	70,429	68,362
Accrued unbilled revenue	38,752	38,017	62,381
Allowance for uncollectible accounts	(1,113)	(1,668)	(956)
Regulatory assets	45,900	34,874	45,781
Derivative instruments	1,130	2,908	1,735
Inventories	35,135	48,484	47,973
Gas reserves	15,124	15,378	15,704
Other current assets	17,460	16,832	25,484
Total current assets	241,694	265,893	269,936
Non-current assets:			
Property, plant, and equipment	3,261,886	3,247,177	3,215,451
Less: Accumulated depreciation	972,776	960,336	960,477
Total property, plant, and equipment, net	2,289,110	2,286,841	2,254,974
Gas reserves	80,560	96,630	84,053
Regulatory assets	343,037	349,057	356,608
Derivative instruments	1,148	46	1,306
Other investments	66,709	68,729	66,363
Other non-current assets	7,081	3,460	6,506
Total non-current assets	2,787,645	2,804,763	2,769,810
Total assets	$3,029,339	$3,070,656	$3,039,746

See Notes to Unaudited Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	March 31, 2018	March 31, 2017	December 31, 2017
Liabilities and equity:			
Current liabilities:			
Short-term debt	$50,000	$—	$54,200
Current maturities of long-term debt	74,785	61,994	96,703
Accounts payable	78,321	73,245	112,308
Taxes accrued	12,352	16,653	18,883
Interest accrued	9,262	10,581	6,773
Regulatory liabilities	34,946	33,211	34,013
Derivative instruments	17,607	1,638	18,722
Other current liabilities	39,580	37,697	40,248
Total current liabilities	316,853	235,019	381,850
Long-term debt	683,497	657,716	683,184
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	283,129	575,451	270,526
Regulatory liabilities	600,442	357,587	586,093
Pension and other postretirement benefit liabilities	221,732	223,253	223,333
Derivative instruments	2,355	2,546	4,649
Other non-current liabilities	149,126	144,469	147,335
Total deferred credits and other non-current liabilities	1,256,784	1,303,306	1,231,936
Commitments and contingencies (see Note 14)			
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 28,781, 28,644, and 28,736 at March 31, 2018 and 2017, and December 31, 2017, respectively	450,408	442,647	448,865
Retained earnings	330,081	438,783	302,349
Accumulated other comprehensive loss	(8,284)	(6,815)	(8,438)
Total equity	772,205	874,615	742,776
Total liabilities and equity	$3,029,339	$3,070,656	$3,039,746

See Notes to Unaudited Consolidated Financial Statements

Table of Contents

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

	Three Months Ended March 31,	
In thousands	2018	2017
Operating activities:		
Net Income	$41,537	$40,310
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	20,985	21,085
Regulatory amortization of gas reserves	4,073	4,107
Deferred income taxes	13,327	20,445
Qualified defined benefit pension plan expense	1,435	1,316
Contributions to qualified defined benefit pension plans	(1,720)	(3,220)
Deferred environmental expenditures, net	(1,280)	(3,432)
Amortization of environmental remediation	4,624	6,954
Regulatory revenue deferral from the TCJA	6,424	—
Other	451	1,695
Changes in assets and liabilities:		
Receivables, net	12,485	23,147
Inventories	13,173	5,645
Income taxes	(6,531)	4,504
Accounts payable	(19,868)	(13,437)
Interest accrued	2,489	4,615
Deferred gas costs	3,519	13,454
Other, net	9,398	17,978
Cash provided by operating activities	104,521	145,166
Investing activities:		
Capital expenditures	(57,431)	(38,924)
Other	(57)	98
Cash used in investing activities	(57,488)	(38,826)
Financing activities:		
Repurchases related to stock-based compensation	—	(1,943)
Long-term debt retired	(22,000)	—
Change in short-term debt	(4,200)	(53,300)
Cash dividend payments on common stock	(12,781)	(13,456)
Other	(309)	(523)
Cash used in financing activities	(39,290)	(69,222)
Increase in cash and cash equivalents	7,743	37,118
Cash and cash equivalents, beginning of period	3,472	3,521
Cash and cash equivalents, end of period	$11,215	$40,639
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalization	$6,261	$4,394
Income taxes paid	9,800	3,040

See Notes to Unaudited Consolidated Financial Statements

8

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), NWN Gas Reserves LLC (NWN Gas Reserves), Northwest Natural Water Company (NWN Water), FWC Merger Sub, Inc., NW Natural Holding Company (NWN Holding) and NWN Merger Sub, Inc. Investments in corporate joint ventures and partnerships we do not directly or indirectly control, and for which we are not the primary beneficiary, include NWN Energy's investment in Trail West Holdings, LLC (TWH), which is accounted for under the equity method, and NWN Financial's investment in Kelso-Beaver 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 2017 Annual Report on Form 10-K (2017 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 2017 Form 10-K. There were no material changes to those accounting policies during the three months ended March 31, 2018 other than those incorporated in Note 5. 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 Oregon Public Utilities Commission (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.

Table of Contents

Amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	March 31,		December 31,
In thousands	2018	2017	2017
Current:			
Unrealized loss on derivatives(1)	$17,569	$1,580	$18,712
Gas costs	591	2,757	154
Environmental costs(2)	5,818	7,574	6,198
Decoupling(3)	9,578	10,087	11,227
Income taxes	2,218	4,378	2,218
Other(4)	10,126	8,498	7,272
Total current	$45,900	$34,874	$45,781
Non-current:			
Unrealized loss on derivatives(1)	$2,355	$2,546	$4,649
Pension balancing(5)	63,940	53,105	60,383
Income taxes	19,267	36,591	19,991
Pension and other postretirement benefit liabilities	175,505	179,586	179,824
Environmental costs(2)	66,730	62,227	72,128
Gas costs	49	114	84
Decoupling(3)	2,663	2,803	3,970
Other(4)	12,528	12,085	15,579
Total non-current	$343,037	$349,057	$356,608

	Regulatory Liabilities		
	March 31,		December 31,
In thousands	2018	2017	2017
Current:			
Gas costs	$17,798	$13,741	$14,886
Unrealized gain on derivatives(1)	1,120	2,870	1,674
Decoupling(3)	2,501	—	322
Other(4)	13,527	16,600	17,131
Total current	$34,946	$33,211	$34,013
Non-current:			
Gas costs	$5,639	$4,740	$4,630
Unrealized gain on derivatives(1)	1,148	46	1,306
Decoupling(3)	1,253	—	957
Income taxes(7)	219,795	—	213,306
Accrued asset removal costs(6)	365,363	345,614	360,929
Other(4)	7,244	7,187	4,965
Total non-current	$600,442	$357,587	$586,093

(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) Refer to footnote (3) per the Deferred Regulatory Asset table in Note 14 for a description of environmental costs.

(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 and typically earn a rate of return or carrying charge.
(5) Refer to footnote (1) of the Net Periodic Benefit Cost table in Note 8 for information regarding the deferral of pension expenses.
(6) Estimated costs of removal on certain regulated properties are collected through rates.
(7) This balance represents estimated amounts associated with the Tax Cuts and Jobs Act. See Note 9.

We believe all costs incurred and deferred at March 31, 2018 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
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. 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 were effective for us beginning January 1, 2018, and will be applied prospectively to any award modified on or after the adoption date. The adoption did not have a material impact to our financial statements or 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. Additionally, the other components of net periodic benefit costs are to be presented 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 were effective for us beginning January 1, 2018.

Upon adoption, the ASU required that changes to the income statement presentation of net periodic benefit cost be applied retrospectively, while changes to amounts capitalized must be applied prospectively. As such, the interest cost, expected return on assets, amortization of prior service costs, and other costs have been reclassified from operations and maintenance expense to other income (expense), net on our consolidated statement of comprehensive income for the three months ended March 31, 2017. We did not elect the practical expedient which would have allowed us to reclassify amounts disclosed previously in the pension and other postretirement benefits footnote disclosure as the basis for applying retrospective presentation. As mentioned above, on a prospective basis, the other components of net periodic benefit cost will not be eligible for capitalization, however, they will continue to be included in our pension regulatory balancing mechanism.

The retrospective presentation requirement related to the other components of net periodic benefit cost affected the operations and maintenance expense and other income (expense), net lines on our consolidated statement of comprehensive income. For the three months ended March 31, 2017, $1.3 million of expense was reclassified from operations and maintenance expense and included in other income (expense), net.

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. The amendments in this standard were effective for us beginning January 1, 2018, and the adoption did not have a material impact to our financial statements or disclosures as our historical practices and presentation were consistent with the directives of this ASU.

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 was effective for us beginning January 1, 2018, and the adoption did not have a material impact to our financial statements or disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The ASU also prescribes a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The guidance also requires additional disclosures, both qualitative and quantitative, regarding the nature, amount, timing and uncertainty of revenue and cash flows.

The new accounting standard and all related amendments were effective for us beginning January 1, 2018. We applied the accounting standard to all contracts using the modified retrospective method. The new standard is primarily reflected in our consolidated statement of comprehensive income and Note 5. The implementation of the new revenue standard did not result in changes to how we currently recognize revenue, and therefore, we did not have a cumulative effect or adjustment to the opening balance of retained earnings. The implementation did result in changes to our disclosures and presentation of revenue and expenses. The comparative information for prior years has not been restated. There is no material impact to our financial results and no significant changes to our control environment due to the adoption of the new revenue standard on an ongoing basis.

As previously discussed, the adoption of the new revenue standard did not impact our consolidated balance sheet or statement of cash flows but did result in changes to the presentation of our consolidated statements of comprehensive income. Had the adoption of the new revenue standard not occurred, our operating revenues would have been $252.3 million, compared to the reported amount of $264.7 million under the new revenue standard for the three months ended March 31, 2018. Similarly, absent the impact of the new revenue standard, our operating expenses would have been $185.0 million, compared to the reported amount of $197.4 million under the new revenue standard for the three months ended March 31, 2018. The effect of the change was an increase in both operating revenues and operating expenses of $12.4 million for the three months ended March 31, 2018 due to the change in presentation of revenue taxes. As part of the adoption of the new revenue standard, we evaluated the presentation of revenue taxes under the new guidance and across our peer group and concluded that the gross presentation of revenue taxes provides the greatest level of consistency and transparency. Prior to the adoption of the new revenue standard, a portion of revenue taxes was presented net in operating revenues and a portion was recorded directly on the balance sheet. During the three months ended March 31, 2018, we recognized $12.4 million in revenue taxes in operating revenues and operating expenses. In comparison, for the three months ended March 31, 2017, we recognized $13.7 million in revenue taxes, of which $7.8 million was recorded in operating revenues and $5.9 million was recorded on the balance sheet. The change in presentation of revenue taxes had no impact on utility margin, net income or earnings per share.

Recently Issued Accounting Pronouncements

ACCUMULATED OTHER COMPREHENSIVE INCOME. On February 14, 2018, the FASB issued ASU 2018-02, "Income Statement—Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income." This update was issued in response to concerns from certain stakeholders regarding the current requirements under U.S. GAAP that deferred tax assets and liabilities are adjusted for a change in tax laws or rates, and the effect is to be included in income from continuing operations in the period of the enactment date. This requirement is also applicable to items in accumulated other comprehensive income where the related tax effects were originally recognized in other comprehensive income. The adjustment of deferred taxes due to the new corporate income tax rate enacted through the Tax Cuts and Jobs Act (TCJA) on December 22, 2017 recognized in income from continuing operations causes the tax effects of items within accumulated other comprehensive income (referred to as stranded tax effects) to not reflect the appropriate tax rate. The amendments in this update allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA and require certain disclosures about stranded tax effects. The amendments in this update are effective for us beginning January 1, 2019, and should be applied either in the period of adoption or retrospectively to each period in which the effect of the change in the federal corporate income tax rate in the TCJA is recognized. The reclassification allowed in this update is elective, and we are currently assessing whether we will make the reclassification. This update is not expected to have a material impact on our financial condition.

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.

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. On November 29, 2017, the FASB proposed an additional practical expedient that would allow entities to apply the transition requirements on the effective date of the standard. Additionally, on January 25, 2018, the FASB issued ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842", to address the costs and complexity of applying the transition provisions of the new lease standard to land easements. This ASU provides an optional practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under the current lease guidance. The standard and associated ASUs are effective for us beginning January 1, 2019. We are currently assessing our lease population and material contracts to determine the effect of this standard on our financial statements and disclosures. Refer to Note 14 of the 2017 Form 10-K for our current lease commitments.

Table of Contents

3. EARNINGS PER SHARE

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

Diluted earnings per share are calculated as follows:

	Three Months Ended March 31,	
In thousands, except per share data	2018	2017
Net income	$41,537	$40,310
Average common shares outstanding - basic	28,753	28,633
Additional shares for stock-based compensation plans (See Note 6)	50	90
Average common shares outstanding - diluted	28,803	28,723
Earnings per share of common stock - basic	$1.44	$1.41
Earnings per share of common stock - diluted	$1.44	$1.40
Additional information:		
Antidilutive shares	16	22

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, non-utility appliance retail center operations, NWN Water, which is pursuing investments in the water sector itself and through its wholly-owned subsidiary FWC Merger Sub, Inc., NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project and NWN Holding, which is pursuing the potential holding company reorganization of NW Natural. See Note 4 in the 2017 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 March 31,			
In thousands	Utility	Gas Storage	Other	Total
2018				
Operating revenues	$257,933	$5,233	$1,546	$264,712
Depreciation and amortization	20,543	442	—	20,985
Income (loss) from operations	64,756	3,036	(444)	67,348

Net income (loss)	39,883	1,898	(244)	41,537
Capital expenditures	56,894	537	—	57,431
Total assets at March 31, 2018	2,951,918	58,676	18,745	3,029,339
2017				
Operating revenues	$292,726	$4,541	$56	$297,323
Depreciation and amortization	19,624	1,461	—	21,085
Income from operations	77,127	606	(201)	77,532
Net income	40,192	61	57	40,310
Capital expenditures	38,854	70	—	38,924
Total assets at March 31, 2017	2,799,638	254,260	16,758	3,070,656
Total assets at December 31, 2017	2,961,326	59,583	18,837	3,039,746

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues, reduced by the associated cost of gas, environmental recovery revenues, and revenue taxes. 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

Table of Contents

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. Revenue taxes are collected from our utility customers and remitted to our taxing authorities. The collections from customers are offset by the expense recognition of the obligation to the taxing authority. By subtracting cost of gas, environmental remediation expense, and revenue taxes 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 March 31,	
In thousands	2018	2017
Utility margin calculation:		
Utility operating revenues	$257,933	$292,726
Less: Utility cost of gas	108,164	143,611
Environmental remediation expense	4,624	6,954
Revenue taxes(1)	12,429	—
Utility margin	$132,716	$142,161

(1) The change in presentation of revenue taxes was a result of the adoption of ASU 2014-09 "Revenue From Contracts with Customers" and all related amendments on January 1, 2018. This change had no impact on utility margin results as revenue taxes were previously presented net in utility operating revenue. For additional information, see Note 2.

5. REVENUE

The following table presents our disaggregated revenue:

	Three Months Ended March 31, 2018			
In thousands	Utility	Gas Storage	Other	Total
Local gas distribution revenue	$258,229	$ —	$—	$258,229
Gas storage revenue, net	—	3,788	—	3,788
Asset management revenue, net	—	1,445	—	1,445
Appliance retail center revenue	—	—	1,546	1,546
Revenue from contracts with customers	258,229	5,233	1,546	265,008
Alternative revenue	(372)	—	—	(372)
Leasing revenue	76	—	—	76
Total operating revenues	$257,933	$ 5,233	$1,546	$264,712

Revenue is recognized when our obligation to our customer is satisfied and in the amount we expect to receive in exchange for transferring goods or providing services. Our revenue from contracts with customers contain one performance obligation that is generally satisfied over time, using the output method based on time elapsed, due to the continuous nature of the service provided. The transaction price is determined per a set price agreed upon in the contract or dependent on regulatory tariffs. Customer accounts are settled on a monthly basis or paid at time of sale and based on historical experience. It is probable that we will collect substantially all of the consideration to which we are entitled to receive.

We do not have any material contract assets as our net accounts receivable and accrued unbilled revenue balances are unconditional and only involve the passage of time until such balances are billed and collected. We do not have any material contract liabilities.

Revenue-based taxes are primarily franchise taxes, which are collected from utility customers and remitted to taxing authorities. Beginning January 1, 2018, revenue taxes are included in operating revenues with an equal and offsetting expense recognized in operating expenses in the consolidated statement of comprehensive income.

Utility Segment

Local gas distribution revenue. Our primary source of revenue is providing natural gas to the customers in our service territory, which include residential, commercial, industrial and transportation customers. Gas distribution revenue is generally recognized over time upon delivery of the gas commodity or service to the customer, and the amount of consideration we receive and recognize as revenue is dependent on the Oregon and Washington tariffs. Customer accounts are to be paid in full each month, and there is no right of return or warranty for services provided. Revenues include firm and interruptible sales and transportation services, franchise taxes recovered from the customer, late payment fees, service fees, and accruals for gas delivered but not yet billed (accrued unbilled revenue). Our accrued unbilled revenue balance is based on estimates of deliveries during the period from the last meter reading and management judgment is required for a number of factors used in this calculation, including customer use and weather factors.

We applied the significant financing practical expedient and we have not adjusted the consideration we expect to receive from our utility customers for the effects of a significant financing component as all payment arrangements are settled annually. Due to the election of the right to invoice practical expedient, we do not disclose the value of unsatisfied performance obligations as of March 31, 2018.

Alternative revenue. Our weather normalization mechanism (WARM) and decoupling mechanism are considered to be alternative revenue programs. Alternative revenue programs are considered to be contracts between us and our regulator and are excluded from revenue from contracts with customers.

Leasing revenue. Leasing revenue primarily consists of rental revenue for small leases of our utility-owned property to third parties. The transactions are accounted for as operating leases and the revenue is recognized on a straight-line basis over the term of the lease agreement. Lease revenue is excluded from revenue from contracts with customers.

Gas Storage Segment

Gas storage revenue. Our gas storage segment includes the non-utility portion of our Mist facility and our ownership interest in the Gill Ranch Facility, which are used to store natural gas for customers. Gas storage revenue is generally recognized over time as the gas storage service is provided to the customer and the amount of consideration we receive and recognize as revenue is dependent on set rates defined per the storage agreements. Noncash consideration in the form of dekatherms of natural gas is received as consideration for providing gas injection services to our gas storage customers. This noncash consideration is measured at fair value using the average spot rate. Customer accounts are generally paid in full each month, and there is no right of return or warranty for services provided. Revenues include firm and interruptible storage services, net of the profit sharing amount refunded to our utility customers.

Asset management revenue. We contract with an independent marketing company to provide asset management services using our storage and pipeline capacity. Asset management revenue is generally recognized over time using a straight-line approach over the term of each contract, and the amount of consideration we receive and recognize as revenue is dependent on a variable pricing model per the agreement. Variable revenues earned above the guaranteed amount are estimated and recognized at the end of each period using the most likely amount approach. Revenues include the optimization of the storage assets and pipeline capacity provided, net of the profit sharing amount refunded to our utility customers. Asset management accounts are settled on a monthly basis.

As of March 31, 2018, unrecognized revenue for the fixed component of the transaction price related to our gas storage and asset management revenue was approximately $75.7 million. Of this amount, approximately $14.3 million will be recognized during the remainder of 2018, $11.8 million in 2019, $9.8 million in 2020, $8.8 million in 2021, $5.6 million in 2022 and $25.4 million thereafter.

Other

Appliance retail center revenue. We own and operate an appliance store that is open to the public, where customers can purchase natural gas home appliances. Revenue from the sale of appliances is recognized at the point in time in which the appliance is transferred to the third party responsible for delivery and installation services and when the customer has legal title to the appliance. It is required that the sale be paid for in full prior to transfer of legal title. The amount of consideration we receive and recognize as revenue varies with changes in marketing incentives and discounts that we offer to our customers.

6. 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 2017 Form 10-K and the updates provided below.

Long Term Incentive Plan

Performance Shares

LTIP performance shares incorporate a combination of market, performance, and service-based factors. During the three months ended March 31, 2018, no performance-based shares were granted under the LTIP for accounting purposes. In February 2018, the 2018 LTIP was awarded to participants; however, the agreement allows for one of the performance factors to remain variable until the first quarter of the third year of the award period. As the performance factor will not be approved until the first quarter of 2020, there is not a mutual understanding of the award’s key terms and conditions between the Company and the participants as of March 31, 2018 and expense was not recognized for the 2018 award. We will calculate the grant date fair value and recognize expense once the final performance factor has been approved.

Table of Contents

For the 2018 LTIP, award share payouts range from a threshold of 0% to a maximum of 200% based on achievement of pre-established goals. The performance criteria for the 2018 performance shares consists of a three-year Return on Invested Capital (ROIC) threshold that must be satisfied and a cumulative EPS factor, which can be modified by a total shareholder return factor (TSR modifier) relative to the performance of the Russell 2500 Utilities Index over the three-year performance period. If the target was achieved for the 2018 award, we would grant 34,702 shares in the first quarter of 2020.

As of March 31, 2018, there was $2.3 million of unrecognized compensation cost associated with the 2016 and 2017 LTIP grants, which is expected to be recognized through 2019.

Restricted Stock Units

During the three months ended March 31, 2018, 23,036 RSUs were granted under the LTIP with a grant date fair value of $54.65 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. An 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 March 31, 2018, there was $3.5 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2022.

7. DEBT

Short-Term Debt

At March 31, 2018, we had short-term debt of $50.0 million, which was comprised entirely of commercial paper. The carrying cost of our commercial paper approximates fair value using Level 2 inputs. See Note 2 in the 2017 Form 10-K for a description of the fair value hierarchy. At March 31, 2018, our commercial paper had a maximum remaining maturity of 51 days and average remaining maturity of 31 days.

Long-Term Debt

At March 31, 2018, we had long-term debt of $758.3 million, which included $6.4 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 4.728%. In March 2018, we retired $22.0 million of FMBs with a coupon rate of 6.60%.

Fair Value of Long-Term Debt

Our outstanding debt does not trade in active markets. We estimate the fair value of our long-term debt using utility companies with similar credit ratings, terms, and remaining maturities to our long-term 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 2017 Form 10-K for a description of the fair value hierarchy.

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

	March 31,		December 31,
In thousands	2018	2017	2017
Gross long-term debt	$764,700	$726,700	$786,700
Unamortized debt issuance costs	(6,418)	(6,990)	(6,813)

Carrying amount	$758,282	$719,710	$779,887
Estimated fair value[1]	$807,288	$785,980	$853,339

[1] Estimated fair value does not include unamortized debt issuance costs.

8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We recognize the service cost component of net periodic benefit cost for our pension and other postretirement benefit plans in operations and maintenance expense in our consolidated statements of comprehensive income. The other non-service cost components are recognized in other income (expense), net in our consolidated statement of comprehensive income. The following table provides the components of net periodic benefit cost for our pension and other postretirement benefit plans:

16

Table of Contents

	Three Months Ended March 31,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2018	2017	2018	2017
Service cost	$1,807	$1,870	$80	$98
Interest cost	4,183	4,472	241	274
Expected return on plan assets	(5,151)	(5,113)	—	—
Amortization of prior service costs	11	32	(117)	(117)
Amortization of net actuarial loss	4,523	3,621	110	138
Net periodic benefit cost	5,373	4,882	314	393
Amount allocated to construction	(682)	(1,521)	(27)	(132)
Amount deferred to regulatory balancing account[(1)]	(2,756)	(1,527)	—	—
Net amount charged to expense	$1,935	$1,834	$287	$261

(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 2017 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 March 31,	
In thousands	2018	2017
Beginning balance	$(8,438)	$(6,951)
Amounts reclassified from AOCL:		
Amortization of actuarial losses	209	225
Total reclassifications before tax	209	225
Tax (benefit) expense	(55)	(89)
Total reclassifications for the period	154	136
Ending balance	$(8,284)	$(6,815)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

For the three months ended March 31, 2018, we made cash contributions totaling $1.7 million to our qualified defined benefit pension plans. We expect further plan contributions of $13.8 million during the remainder of 2018.

Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Sections 401(a) and 401(k). Employer contributions totaled $2.0 million and $1.6 million for the three months ended March 31, 2018 and 2017, respectively.

See Note 8 in the 2017 Form 10-K for more information concerning these retirement and other postretirement benefit plans.

9. 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.

17

Table of Contents

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

	Three Months Ended March 31,	
Dollars in thousands	2018	2017
Income taxes at statutory rates (federal and state)	$15,198	$26,600
Increase (decrease):		
Differences required to be flowed-through by regulatory commissions	849	1,518
Other, net	(585)	(1,195)
Total provision for income taxes	$15,462	$26,923
Effective tax rate	27.1 %	40.0 %

The effective income tax rate for the three months ended March 31, 2018 compared to the same period in 2017 decreased primarily as a result of the TCJA and lower pre-tax income. See "U.S. Federal TCJA Matters" below and Note 9 in the 2017 Form 10-K for more detail on income taxes and effective tax rates.

The IRS Compliance Assurance Process (CAP) examination of the 2016 tax year was completed during the first quarter of 2018. There were no material changes to the return as filed. The 2017 tax year is subject to examination under CAP and the 2018 tax year CAP application has been accepted by the IRS.

U.S. Federal TCJA Matters

On December 22, 2017, the TCJA was enacted and permanently lowered the U.S. federal corporate income tax rate to 21% from the previous maximum rate of 35%, effective for our tax year beginning January 1, 2018. The TCJA includes specific provisions related to regulated public utilities that provide for the continued deductibility of interest expense and the elimination of bonus depreciation for property acquired and placed in service after September 27, 2017.

Under pre-TCJA law, business interest expense was generally deductible in the determination of taxable income. The TCJA imposes a new limitation on the deductibility of net business interest expense in excess of approximately 30% of adjusted taxable income. Taxpayers operating in the trade or business of public regulated utilities are excluded from these new interest expense limitations. There is ongoing uncertainty with regards to the application of the new interest expense limitation to our non-regulated operations. See Note 9 in the 2017 Form 10-K.

The TCJA generally provides for immediate full expensing for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. This would generally provide for accelerated cost recovery for capital investments. However, the definition of qualified property excludes property used in the trade or business of a public regulated utility. The definition of utility trade or business is the same as that used by the TCJA with respect to the imposition of the net interest expense limitation discussed above. As a result, ongoing uncertainty exists with respect to the application of full expensing to our non-regulated activities, and the availability of bonus depreciation for utility assets acquired before September 28, 2017 and placed in service after September 27, 2017. See Note 9 in the 2017 Form 10-K.

At March 31, 2018 and December 31, 2017, we had an estimated regulatory liability of $213.3 million for the change in regulated utility deferred taxes as a result of the TCJA, which included a gross-up for income taxes of $56.5 million. It is possible that this estimated balance may increase or decrease in the future as additional authoritative interpretation of the TCJA becomes available, or as a result of regulatory guidance from the OPUC or WUTC. We anticipate that until such time that customers receive the direct benefit of this regulatory liability, the balance, net of the additional gross-up for income taxes, will continue to provide an indirect benefit to customers by reducing the utility rate base which is a component of customer rates. It is not possible at this time to determine when the final resolution of these regulatory proceedings will occur, and as result, this regulatory liability is classified as long-term.

Utility rates in effect include an allowance to provide for the recovery of the anticipated provision for income taxes incurred as a result of providing regulated services. As a result of the newly enacted 21% federal corporate income tax rate, we are recording an additional regulatory liability in 2018 reflecting the estimated net reduction in our provision for income taxes. This revenue deferral is based on the estimated net benefit to customers using forecasted regulated utility earnings, considering average weather and associated volumes, and includes a gross-up for income taxes. As of March 31, 2018, a regulatory liability of $6.5 million has been recorded including accrued interest to reflect this estimated revenue deferral.

Table of Contents

10. PROPERTY, PLANT, AND EQUIPMENT

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

	March 31,		December 31,
In thousands	2018	2017	2017
Utility plant in service	$3,003,962	$2,867,271	$2,975,217
Utility construction work in progress	177,133	76,631	159,924
Less: Accumulated depreciation	954,858	914,179	942,879
Utility plant, net	2,226,237	2,029,723	2,192,262
Non-utility plant in service	76,436	299,324	75,639
Non-utility construction work in progress	4,355	3,951	4,671
Less: Accumulated depreciation	17,918	46,157	17,598
Non-utility plant, net	62,873	257,118	62,712
Total property, plant, and equipment	$2,289,110	$2,286,841	$2,254,974
Capital expenditures in accrued liabilities	$21,923	$11,564	$34,976

Build-to-suit assets

In October 2017, we entered into a 20-year operating lease agreement commencing in 2020 for our new headquarters location in Portland, Oregon. Our existing headquarters lease expires in 2020. Our search and evaluation process focused on seismic preparedness, safety, reliability, least cost to our customers, and a continued commitment to our employees and the communities we serve. The lease was analyzed in consideration of build-to-suit lease accounting guidance, and we concluded that we are the accounting owner of the asset during construction. As a result, we have recognized $4.1 million and $0.5 million in property, plant and equipment and an obligation in other non-current liabilities for the same amount in our consolidated balance sheet at March 31, 2018 and December 31, 2017, respectively. In 2019, pursuant to the new lease standard issued by the FASB, we expect to de-recognize the associated build-to-suit asset and liability. See Note 14 in our 2017 Form 10-K.

11. GAS RESERVES

We have invested $188.0 million through our gas reserves program in the Jonah Field located in Wyoming as of March 31, 2018. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities in 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 $178.0 million and the amended agreement with Jonah Energy LLC under which an approximate additional $10 million was invested.

The cost of gas, including a carrying cost for the rate base investment, 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.

Gas produced from the additional wells is 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:

	March 31,		December 31,
In thousands	2018	2017	2017
Gas reserves, current	$15,124	$15,378	$ 15,704
Gas reserves, non-current	172,412	172,158	171,832
Less: Accumulated amortization	91,852	75,528	87,779
Total gas reserves[1]	95,684	112,008	99,757
Less: Deferred taxes on gas reserves	22,115	32,179	22,712
Net investment in gas reserves	$73,569	$79,829	$ 77,045

(1) Our net investment in additional wells included in total gas reserves was $5.6 million, $6.5 million and $5.8 million at March 31, 2018 and 2017 and December 31, 2017, respectively.

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

Table of Contents

12. 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 in our balance sheet. If we do not develop this investment, 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 March 31, 2018 and 2017 and December 31, 2017. See Note 12 in our 2017 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 our 2017 Form 10-K.

13. 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:

	March 31,	December

In thousands	2018	2017	31, 2017
Natural gas (in therms):			
Financial	326,080	382,850	429,100
Physical	420,200	368,700	520,268
Foreign exchange	$7,611	$6,629	$ 7,669

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. We entered the 2017-18 and 2016-17 gas year with our forecasted sales volumes hedged at 49% and 48% in financial swap and option contracts, and 26% and 27% in physical gas supplies, respectively. Hedge contracts entered into prior to our PGA filing, in September 2017, were included in the PGA for the 2017-18 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.

Table of Contents

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 March 31,			
	2018		2017	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$(5,747)	$ (154)	$(13,094)	$ 26
Operating expenses	(227)	—	(1,226)	—
Amounts deferred to regulatory accounts on balance sheet	5,895	154	13,893	(26)
Total gain (loss) in pre-tax earnings	$(79)	$ —	$(427)	$ —

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

REALIZED GAIN/LOSS. We realized net losses of $9.0 million and $0.3 million for the three months ended March 31, 2018 and 2017, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of March 31, 2018 or 2017. 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 2018 or 2017. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change.

Based upon current commodity financial swap and option contracts outstanding, which reflect unrealized losses of $19.5 million at March 31, 2018, 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	$ —	$ —	$ —	$ (8,851)	$ (30,172)
Without Adequate Assurance Calls	—	—	—	(7,112)	(18,433)

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 $2.2 million and a liability of $19.9 million as of March 31, 2018, an asset of $1.7 million and a liability of $2.9 million as of March 31, 2017, and an asset of $2.9 million and a liability of $23.3 million as of December 31, 2017.

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 2017 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 March 31, 2018. Using significant other observable or

Level 2 inputs, the net fair value was a liability of $17.7 million, $1.2 million, and $20.3 million as of March 31, 2018 and 2017, and December 31, 2017, respectively. No Level 3 inputs were used in our derivative valuations, and there were no transfers between Level 1 or Level 2 during the three months ended March 31, 2018 and 2017. See Note 2 in the 2017 Form 10-K.

14. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties (PRPs). When amounts are prudently expended related to site remediation, of those sites described herein, we have a recovery mechanism in place to collect 96.68% of remediation costs from Oregon customers, and we are allowed to defer environmental remediation costs allocated to customers in Washington annually until they are reviewed for prudence at a subsequent proceeding.

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

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

Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated where a range of potential loss is available. Unless there is an estimate within the range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives. In addition to remediation costs, we could also be subject to Natural Resource Damages (NRD) claims from third-party tribal entities. We will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. 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 in the balance sheet:

	Current Liabilities			Non-Current Liabilities		
	March 31,		December 31,	March 31,		December 31,
In thousands	2018	2017	2017	2018	2017	2017
Portland Harbor site:						
Gasco/Siltronic Sediments	$2,797	$1,573	$ 2,683	$45,015	$43,200	$45,346
Other Portland Harbor	1,769	1,804	1,949	3,928	3,940	4,163
Gasco/Siltronic Upland site	11,408	10,335	13,422	46,769	50,189	47,835
Central Service Center site	25	68	25	—	—	—
Front Street site	764	858	1,009	10,720	7,777	10,757
Oregon Steel Mills	—	—	—	179	179	179
Total	$16,763	$14,638	$ 19,088	$106,611	$105,285	$108,280

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 selects the remedy for the clean-up of the Portland Harbor

22

site (Portland Harbor ROD). 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 for the additional studies and design work needed before the cleanup can occur, and for regulatory oversight throughout the clean-up range from $47.8 million to $350 million. We have recorded a liability of $47.8 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site discussed above.

Other Portland Harbor. 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 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 has filed two amended complaints addressing certain pleading defects and dismissing the State of Oregon. 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 September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

OTHER SITES. In addition to those sites above, we have environmental exposures at three other sites: Central Service Center, Front Street and Oregon Steel Mills. We may have exposure at other sites that have not been identified at this time. Due to the uncertainty of the design of remediation, regulation, timing of the remediation and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized 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 $1.0 million for additional studies and design costs as well as regulatory oversight throughout the clean-up. We plan to complete the remedial design in 2018 and expect to construct the remedy details 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 therein. See Note 15 in the 2017 Form 10-K for a description of the SRRM collection process.

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

	March 31,		December 31,
In thousands	2018	2017	2017
Deferred costs and interest [1]	$44,686	$49,373	$45,546
Accrued site liabilities [2]	122,962	119,623	126,950
Insurance proceeds and interest	(95,100)	(99,195)	(94,170)
Total regulatory asset deferral[1]	$72,548	$69,801	$78,326
Current regulatory assets[3]	5,818	7,574	6,198
Long-term regulatory assets[3]	66,730	62,227	72,128

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

(2) Excludes 3.32% of the Front Street site liability, or $0.4 million in 2018 and $0.4 million in 2017, as the OPUC only 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 $5.0 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 $5.0 million tariff rider and $5.0 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 $10.0 million with those earnings that exceed its authorized ROE.

Under the 2015 Order, the OPUC stated they would 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 we gain greater certainty about our future remediation costs, to consider whether adjustments to the mechanism may be appropriate. As it has been three years from the 2015 Order, we filed an update with the OPUC in March 2018 and recommended no changes.

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.

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. See Note 15 in the 2017 Form 10-K.

For additional information regarding other commitments and contingencies, see Note 14 in the 2017 Form 10-K.

Table of Contents

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

The following is management's assessment of Northwest Natural Gas Company's (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated results for the quarters ended March 31, 2018 and 2017. 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 2017 Annual Report on Form 10-K (2017 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);
- NWN Gas Reserves LLC (NWN Gas Reserves);
- NW Natural Water Company, LLC (NWN Water);
- FWC Merger Sub, Inc.;
- NW Natural Holding Company (NWN Holding); and
- NWN Merger Sub, Inc. (NWN Holdco Sub).

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. See Note 4 for further discussion of our business segments and other, as well as our direct and indirect wholly-owned subsidiaries.

NON-GAAP FINANCIAL MEASURES. In addition to presenting the results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which are non-GAAP financial measures. Non-GAAP 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.

Table of Contents

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 "2018 Outlook" in our 2017 Form 10-K for more information. Current operational highlights include:

- added nearly 12,000 customers during the past twelve months for a growth rate of 1.6% at March 31, 2018;
- invested $57.4 million in our distribution system and facilities for growth and reliability; and
- deployed $115.8 million of capital expenditures into the North Mist gas storage expansion project as of March 31, 2018, and expect the project to be in-service during the fourth quarter of 2018.

Key financial highlights include:

	Three Months Ended March 31,				
	2018		2017		$
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Consolidated net income	$41,537	$1.44	$40,310	$1.40	$1,227
Utility margin	132,716		142,161		(9,445)
Gas storage operating revenues	5,233		4,541		692

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. Consolidated net income increased $1.2 million primarily due to the following factors:

- an $11.5 million decrease in income tax expense due to the benefit from the decline of the U.S. federal corporate income tax rate to 21% in 2018 from 35% in the prior period, as well as changes in pre-tax income; partially offset by
- a $9.4 million decrease in utility margin due to a regulatory revenue deferral associated with the TCJA and warmer than average weather in 2018, partially offset by customer growth; and
- a $1.4 million increase in operations and maintenance expense largely from payroll and benefits due to increased headcount and general salary increases.

HOLDING COMPANY

NW Natural intends to pursue formation of a holding company to best position it to be able to respond to opportunities and risks in a manner that serves the best interests of its shareholders and customers. We have received regulatory approval from the OPUC and WUTC and expect regulatory approval from the CPUC to reorganize into a holding company structure. Our Board of Directors has proposed a holding company structure to our shareholders for a vote at our 2018 Annual Shareholders Meeting. If our shareholders approve the proposal, the Board and Management must take additional actions to implement the holding company structure, which we currently expect to happen in the latter half of 2018 or at the beginning of 2019. To implement a holding company structure, NW Natural common stock would be converted or exchanged into the same relative percentages of the holding company that each shareholder owns of NW Natural immediately prior to the reorganization. The structure currently contemplated involves placing a non-operating corporate entity over the existing consolidated structure, and “ring-fencing” NW Natural to insulate the gas utility from the operations of the holding company and its other direct and indirect subsidiaries. NW Natural management continuously looks for growth opportunities that would build on core competencies and match the risk profile that NW Natural and its shareholders seek. We believe a holding company structure is a more agile and efficient platform from which to pursue, finance and oversee new business growth opportunities, such as in the water sector. Following the formation of the holding company, NW Natural would continue to operate as a gas utility subject to the jurisdiction of the OPUC and the WUTC. For more information regarding the proposed holding company structure, see Part I, Item 1A "Risk Factors" in our 2017 Form 10-K.

DIVIDENDS

Dividend highlights include:

	Three Months Ended March 31,		
Per common share	2018	2017	Change
Dividends paid	$0.4725	$0.4700	$0.0025

In April 2018, the Board of Directors declared a quarterly dividend on our common stock of $0.4725 per share, payable on May 15, 2018, to shareholders of record on April 30, 2018, reflecting an annual indicated dividend rate of $1.89 per share.

RESULTS OF OPERATIONS

Regulatory Matters

For additional information, see Part II, Item 7 "Results of Operations—Regulatory Matters" in our 2017 Form 10-K.

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 2017, 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 2017, approximately 70% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 30% 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. In January 2018, various state parties filed a request with the FERC to adjust the revenue requirements of public utilities to reflect the recent reduction in the federal corporate income tax rate and other impacts resulting from the TCJA. We will monitor this request and work with the FERC to evaluate the potential impact to these approved rates.

We continuously monitor the utility and evaluate the need for a rate case. In December 2017, we filed a rate case in Oregon with the OPUC. For additional information, see "Regulatory Proceeding Updates" below.

Table of Contents

Rate Mechanisms

During 2018, our key approved rates and recovery mechanisms for each service area included:

	Oregon	Washington
Authorized Rate Structure:		
ROE	9.5%	10.1%
ROR	7.8%	8.4%
Debt/Equity Ratio	50%/50%	49%/51%
Key Regulatory Mechanisms:		
PGA	X	X
Gas Cost Incentive Sharing	X	
Decoupling	X	
WARM	X	
Environmental Cost Deferral	X	X
SRRM	X	
Pension Balancing	X	
Interstate Storage Sharing	X	

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

Each year, we typically hedge gas prices on 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 with our forecasted sales volumes hedged at 49% in financial swap and option contracts and 26% in physical gas supplies.

As of March 31, 2018, we are also hedged in future gas years at approximately 26% for the 2018-19 gas year and between 2% and 11% 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.

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 gas year, 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.

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 2016-17 and 2017-18 gas years, we selected the 90% deferral option. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar year 2017, the ROE threshold was 10.66%. We filed the 2017 earnings test in May 2018 and do not expect a customer refund adjustment for 2017 based on our results.

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.

Table of Contents

In 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 the 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 the three months ended March 31, 2018.

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.

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 March 31, 2018, 8% 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, which are intended to give us certainty in the level of gas supplies we need to acquire to serve this customer group. The approved terms include, among other things, an annual election period, special pricing provisions for out-of-cycle changes, and a requirement that industrial customers complete the term of their service election under our annual PGA tariff.

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

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

•

- 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 $5.0 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 our Consolidated Statement of Comprehensive Income (Loss). For additional information, see Note 15 in our 2017 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: $5.0 million base rate rider
    Prior year carry-over[1]
    $5.0 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[2]
Total amount transferred to post-review

(1) 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.

(2) 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), the total amount transferred to post-review is recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the amount transferred to post-review would be reduced by those earnings that exceed its authorized ROE.

For 2017, we have performed this test, which we submitted to the OPUC in May 2018, and do not expect an earnings test adjustment based on our results.

The WUTC has also previously authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This Order was effective in January 2011 with cost recovery and carrying charges on the amount deferred for costs associated with services provided to Washington customers to be determined in a future proceeding. Annually, or more often if circumstances warrant, we review all regulatory assets for recoverability. 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. The OPUC permits us to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return. 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 $2.8 million and $1.5 million during the three months ended March 31, 2018 and 2017, respectively.

INTERSTATE STORAGE AND OPTIMIZATION SHARING. On an annual basis, we credit amounts to Oregon and Washington utility customers as part of our regulatory incentive sharing mechanism related to net revenues earned from Mist gas storage and asset management activities. Generally, amounts are credited to Oregon customers in June, while credits are given to customers in Washington through reductions in rates through the annual PGA filing in November.

Regulatory Proceeding Updates

During 2018, we were involved in the regulatory activities discussed below. For additional information, see Part II, Item 7 "Results of Operations—Regulatory Matters" in our 2017 Form 10-K.

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 required a third-party cost study to be performed. In 2017, a third-party consultant completed a cost study and their final report was filed with the OPUC in February 2018. We will review and address the study as part of our current Oregon general rate case proceeding. For additional information, see "Oregon General Rate Case" below.

HOLDING COMPANY APPLICATION. In February 2017, we filed applications with the OPUC, WUTC, and CPUC for approval to reorganize under a holding company structure. In 2017, the OPUC and WUTC approved our applications subject to certain restrictions or "ring-fencing" provisions applicable to NW Natural, the entity that currently, and would continue to, house our utility operations. We continue to work with the CPUC for approval and expect a resolution during the second quarter of 2018.

TAX REFORM DEFERRAL. In December 2017, we filed applications with the OPUC and WUTC to defer the overall net benefit associated with the TCJA that was enacted on December 22, 2017 with a January 1, 2018 effective date. We anticipate the impacts from the TCJA will accrue to the benefit of our customers in a manner approved by the Commissions. We are working with the OPUC to determine the treatment of deferred amounts prior to November 1, 2018. In addition, we updated our Oregon

Table of Contents

general rate case request to reflect the effects of the TCJA on future rates beginning November 1, 2018. For additional information, see "Oregon General Rate Case" below. We expect to work with the WUTC regarding the Washington deferral for the TCJA in a future rate case filing and are currently deferring all amounts for Washington customers.

REGULATED WATER UTILITY. In December 2017, we entered into agreements to acquire two privately-owned water utilities: Salmon Valley Water Company, based in Welches, Oregon, and Falls Water Company, based in Idaho Falls, Idaho. These transactions are subject to certain conditions, including approvals from the OPUC and the Idaho Public Utilities Commission (IPUC), respectively. In January 2018, we filed our application with the OPUC to acquire Salmon Valley Water Company and filed with the IPUC in February 2018 to acquire Falls Water Company. We do not expect these transactions or their continuing operations to have a material financial impact. We continue to work with the OPUC and IPUC and anticipate receiving approvals and closing these acquisitions in 2018.

OREGON GENERAL RATE CASE. On December 2017, we filed an Oregon general rate case requesting a $40.4 million or 6% revenue requirement increase, after an adjustment for the conversation tariff deferral, to continue operating and maintaining our distribution system and providing safe, reliable service to our customers. In March 2018, we made supplemental filings in the rate case to incorporate the effect of the TCJA on future rates. As a result, our requested annual revenue requirement increase is $25.7 million, or approximately a 4% increase, after an adjustment for our conservation tariff deferral. The revised revenue requirement is based upon the following assumptions or requests:

- Forward test year from November 1, 2018 through October 31, 2019;
- Capital structure of 50% debt and 50% equity;
- Return on equity of 10.0%;
- Cost of capital of 7.62%; and
- Rate base of $1.215 billion or an increase of $329 million since the last rate case.

The supplemental filings adjusting the revenue requirement for the TCJA does not include the treatment of historical deferred tax liabilities, which is being addressed in a tax deferral docket with the OPUC. For additional information, see "Tax Reform Deferral" above.

In addition, in March 2018, we made a supplemental filing to incorporate the interstate storage and optimization sharing open proceeding in the rate case docket. To conclude this process, the OPUC, parties to the proceedings, and NW Natural will address matters raised in the cost study completed by a third-party.

In April 2018, staff of the OPUC, the Citizen's Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) filed their testimony. We have engaged in discussions with parties during initial scheduled settlement conferences. We expect to file our reply testimony in May 2018 with regulatory review of the case continuing through 2018. A final order is anticipated in or before October 2018 with new customer rates expected to be effective November 1, 2018.

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. For additional information, see Part II, Item 7 "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2017 Form 10-K.

Utility segment highlights include:

	Three Months Ended March 31,		
Dollars and therms in thousands, except EPS data	2018	2017	QTR Change
Utility net income	$39,883	$40,192	$(309)
EPS - utility segment	$1.39	$1.40	$(0.01)
Gas sold and delivered (in therms)	406,953	467,639	(60,686)
Utility margin(1)	$132,716	$142,161	$(9,445)

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

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. The primary factors contributing to the $0.3 million, or $0.01 per share, decrease in utility net income were as follows:

- a $9.4 million decrease in utility margin due to:

Table of Contents

- a $6.4 million decrease due to a regulatory revenue deferral associated with the decline of the U.S. federal corporate income tax rate to 21% in 2018 from 35% in the prior period until customer rates can be reset to reflect the lower tax rate, offset by
- a $1.7 million increase from customer growth.
- The majority of the remaining decrease was due to the return of relatively average weather in 2018 compared to 26% colder than average weather in the prior period.
- a $1.2 million increase in operations and maintenance expense largely from payroll and benefits due to increased headcount and general salary increases; and
- a $2.3 million increase in additional expenses related to depreciation, other income and expenses, net, and property taxes; partially offset by
- a $12.3 million decrease in income tax expense largely due to the decline of the U.S. federal corporate income tax rate to 21% in 2018 compared to 35% in the prior period.

Total utility volumes sold and delivered in the three months ended March 31, 2018 decreased 13% over the same period in 2017 due to 5% warmer than average weather in 2018 compared to 26% colder than average weather in 2017.

As mentioned above, we deferred $6.4 million of revenue during the first quarter of 2018 related to the estimated effects of the TCJA. The revenue deferral is based on the estimated net benefit of the TCJA to customers for the year using forecasted regulated utility earnings, considering average weather and associated volumes. We currently estimate the deferral for 2018 will be $8-12 million pre-tax. Additionally, during 2018, we expect the lower tax rate will increase the seasonality of gas utility earnings as the lower rate improves earnings in the heating season and reduces the tax benefit associated with losses in the non-heating periods.

Table of Contents

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 March 31, 2018	2017	Favorable/ (Unfavorable) QTD Change
Utility volumes (therms):			
Residential and commercial sales	278,019	327,523	(49,504)
Industrial sales and transportation	128,934	140,116	(11,182)
Total utility volumes sold and delivered	406,953	467,639	(60,686)
Utility operating revenues:			
Residential and commercial sales	$245,584	$280,277	$(34,693)
Industrial sales and transportation	17,389	18,903	(1,514)
Other revenues	(5,040)	1,375	(6,415)
Less: Revenue taxes(1)	—	7,829	7,829
Total utility operating revenues	257,933	292,726	(34,793)
Less: Cost of gas	108,164	143,611	35,447
Less: Environmental remediation expense	4,624	6,954	2,330
Less: Revenue taxes(1)	12,429	—	(12,429)
Utility margin	$132,716	$142,161	$(9,445)
Utility margin:(2)			
Residential and commercial sales	$128,454	$131,040	$(2,586)
Industrial sales and transportation	8,304	8,692	(388)
Miscellaneous revenues	1,358	1,373	(15)
Gain from gas cost incentive sharing	880	951	(71)
Other margin adjustments(5)	(6,280)	105	(6,385)
Utility margin	$132,716	$142,161	$(9,445)
Degree days(3)			
Average(4)	1,326	1,326	—
Actual	1,256	1,667	(25)%
Percent colder (warmer) than average weather	(5)%	26%	

Customers - end of period:	As of March 31, 2018	2017	Change
Residential customers	672,570	661,217	11,353
Commercial customers	68,322	67,838	484
Industrial customers	1,028	1,012	16
Total number of customers	741,920	730,067	11,853
Customer growth:			
Residential customers	1.7%		
Commercial customers	0.7%		
Industrial customers	1.6%		
Total customer growth	1.6%		

(1) The change in presentation of revenue taxes was a result of the adoption of ASU 2014-09 "Revenue From Contracts with Customers" and all related amendments on January 1, 2018. This change had no impact on utility margin results. For additional information, see Note 2.

(2)

Amounts reported as margin for each category of customers are total operating revenues less cost of gas, environmental remediation expense, and revenue tax expense.

(3) Heating degree days are units of measure reflecting temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperatures from 59 degrees Fahrenheit.

(4) Average weather represents the 25-year average of heating degree days, over the period 1986 - 2010, as determined in our 2012 Oregon general rate case.

(5) Other margin adjustments includes the $6.4 million regulatory revenue deferral in 2018 associated from the decline of the U.S. federal corporate income tax rate.

Table of Contents

Residential and Commercial Sales

Residential and commercial sales highlights include:

In thousands	Three Months Ended March 31, 2018	2017	QTR Change
Volumes (therms):			
Residential sales	177,971	209,650	(31,679)
Commercial sales	100,048	117,873	(17,825)
Total volumes	278,019	327,523	(49,504)
Operating revenues:			
Residential sales	$166,587	$188,568	$(21,981)
Commercial sales	78,997	91,709	(12,712)
Total operating revenues	$245,584	$280,277	$(34,693)
Utility margin:			
Residential:			
Sales	$90,529	$106,723	$(16,194)
Alternative Revenue:			
Weather normalization	1,843	(11,302)	13,145
Decoupling	(2,409)	(2,054)	(355)
Amortization of alternative revenue	783	(1,143)	1,926
Total residential utility margin	90,746	92,224	(1,478)
Commercial:			
Sales	38,297	46,175	(7,878)
Alternative Revenue:			
Weather normalization	593	(4,359)	4,952
Decoupling	2,594	2,999	(405)
Amortization of alternative revenue	(3,776)	(5,999)	2,223
Total commercial utility margin	37,708	38,816	(1,108)
Total utility margin	$128,454	$131,040	$(2,586)

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. The primary factor contributing to the $2.6 million decrease in residential and commercial utility margin is a decline in usage from the return of relatively average weather in 2018 compared to colder than average weather in the prior period, and the effect on customers that opt out of our weather normalization mechanism in Oregon and customers in Washington that do not have this mechanism. Partially offsetting this decline was higher customer growth.

Industrial Sales and Transportation

Industrial sales and transportation highlights include:

In thousands	Three Months Ended March 31, 2018	2017	QTR Change
Volumes (therms):			
Industrial - firm sales	10,008	10,376	(368)

Industrial - firm transportation	45,376	48,729	(3,353)
Industrial - interruptible sales	15,605	16,977	(1,372)
Industrial - interruptible transportation	57,945	64,034	(6,089)
Total volumes	128,934	140,116	(11,182)
Utility margin:			
Industrial - firm and interruptible sales	$3,237	$3,340	$(103)
Industrial - firm and interruptible transportation	5,067	5,352	(285)
Industrial - sales and transportation	$8,304	$8,692	$(388)

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. Sales and transportation volumes decreased by 11.2 million therms, or 8%, in sales volumes and decreased by $0.4 million in industrial utility margin, net.

35

Table of Contents

Cost of Gas

Cost of gas highlights include:

	Three Months Ended March 31,		
Dollars and therms in thousands	2018	2017	QTR Change
Cost of gas	$108,164	$143,611	$(35,447)
Volumes sold (therms)[1]	303,632	354,876	(51,244)
Average cost of gas (cents per therm)	$0.36	$0.40	$(0.04)
Gain from gas cost incentive sharing[2]	$880	$951	$(71)

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

(2) For additional information regarding our gas cost incentive sharing mechanism, see Part II, Item 7 "Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves" in our 2017 Form 10-K.

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. Cost of gas decreased $35.4 million, or 25%, primarily due to a 14% decrease in volumes sold due to the return of relatively average weather in 2018 compared to colder than average weather in the prior period, and a 10% decrease in average cost of gas due to lower natural gas prices, slightly offset by customer growth.

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 Facility, an 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. For additional information, see Note 4.

Gas storage segment highlights include:

	Three Months Ended March 31,		
In thousands, except EPS data	2018	2017	QTR Change
Operating revenues	$5,233	$4,541	$ 692
Operating expenses	2,197	3,935	(1,738)
Gas storage net income	1,898	61	1,837
EPS - gas storage segment	0.06	—	0.06

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. The primary factors contributing to the $1.8 million, or $0.06 per share, increase in gas storage net income were as follows:

- a $1.7 million decrease in operating expenses primarily due to a $1.0 million benefit from lower depreciation expense as a result of the impairment of long-lived assets at the Gill Ranch Facility in the fourth quarter of 2017, and
- a $0.7 million increase in gas storage revenues due to higher asset management revenues from our Mist facility and transportation capacity, offset by slightly lower firm prices at the Gill Ranch Facility for the 2017-18 storage year.

We have substantially completed contracting for the 2018-19 gas storage year for our Mist facility, which remains under long-term contracts at similar prices to prior periods. Our Mist facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location.

Market prices for natural gas storage in California remain low due to the abundant supply for natural gas, low volatility of natural gas prices, and surplus gas capacity in California. We have substantially completed contracting for the 2018-19 gas storage year for our Gill Ranch Facility, which consists of short-term agreements at slightly lower prices than the 2017-18 gas storage year.

The California Department of Oil Gas and Geothermal Resources (DOGGR) proposed new regulations for gas storage wells that focus on additional well integrity requirements in response to a significant natural gas leak in southern California in 2015. In February 2018 and subsequently in March 2018, DOGGR released a draft of these rules. Although these rules are subject to a comment period and possible revision, the main aspects of the rules are unlikely to materially change, including the timeframe for completion of compliance in seven years, a period much shorter than the 15 or more years in previous drafts. In addition, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) proposed new federal regulations for underground natural gas storage facilities that would focus on implementing additional pipeline safety requirements for downhole facilities, including operations, maintenance, and emergency response activities regarding wells, wellbore tubing, and casing. DOGGR rules are expected to be finalized in the second quarter of 2018, whereas PHMSA regulations are expected to be finalized during 2019. It is likely these additional regulations will result in higher costs for all storage providers, and we are currently assessing those costs.

Table of Contents

Other

Other primarily consists of our non-utility appliance retail center operations, NNG Financial's investment in KB Pipeline, an equity investment in TWH, which has invested in the Trail West pipeline project, costs associated with our regulated water strategy, costs associated with potential holding company activities, and other non-utility investments and business development activities. For the three months ended March 31, 2018, other net loss was $0.2 million, or $0.01 per share, compared to net income of $0.1 million, or $0.00 per share, in the prior period. Net income decreased $0.3 million primarily due to an increase in costs associated with business development activities, including costs associated with regulated water and the potential holding company activities. See Note 4 and Note 12 for further details on other activities and our investment in TWH, respectively.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

	Three Months Ended March 31,		
In thousands	2018	2017	QTR Change
Operations and maintenance	$40,559	$39,116	$ 1,443

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. Operations and maintenance expense increased $1.4 million reflecting higher utility payroll and benefits due to increased headcount and general salary increases.

Delinquent customer receivable balances continue to remain low. The utility's annualized bad debt expense as a percent of revenues was 0.1% for both the three months ended March 31, 2018 and 2017.

Interest Expense, Net

Interest expense, net highlights include:

	Three Months Ended March 31,		
In thousands	2018	2017	QTR Change
Interest expense, net	$9,515	$9,876	$ (361)

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. Interest expense, net decreased $0.4 million primarily due to a $0.6 million increase in the interest-related portion of AFUDC, partially offset by a $0.2 million increase in interest expense due to an increase of long-term debt as of March 31, 2018 compared to the prior period.

Income Tax Expense

Income tax expense highlights include:

Three Months
Ended March 31,

In thousands	2018	2017	QTR Change
Income tax expense	$15,462	$26,923	$(11,461)

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. Income tax expense decreased $11.5 million due to the benefit from the decline of the U.S. federal corporate income tax rate to 21% in 2018 from 35% in the prior period, as well as lower pre-tax income.

FINANCIAL CONDITION

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure with a long-term 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 7.

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.

Table of Contents

Our consolidated capital structure was as follows:

	March 31,		December 31,
	2018	2017	2017
Common stock equity	48.9 %	54.8 %	47.1 %
Long-term debt	43.2	41.3	43.3
Short-term debt, including current maturities of long-term debt	7.9	3.9	9.6
Total	100.0%	100.0%	100.0 %

Liquidity and Capital Resources

At March 31, 2018 we had $11.2 million of cash and cash equivalents compared to $40.6 million at March 31, 2017 due to lower cash collections from customers as a result of warmer weather in the first quarter of 2018 as compared to the first quarter of 2017. 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, 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. See "Credit Ratings" below. 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, and satisfaction of provisions of our mortgage.

Our issuance of FMBs, which includes our medium-term notes, under our mortgage and deed of trust is limited by eligible properties, satisfaction of an adjusted net earnings test, and other provisions of the mortgage. The non-cash impairment of long-lived assets at the Gill Ranch Facility in December 2017 is expected to result in our inability to satisfy the earnings test throughout most of 2018. However, we are permitted to issue FMBs without meeting the earnings test on the basis of the $97.0 million of FMBs maturing in 2018, an amount that is sufficient to accommodate our expected issuances of FMBs in 2018. There is no similar restriction on our ability to issue unsecured long-term debt.

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 March 31, 2018. However, if the credit risk-related contingent features underlying these contracts were triggered on March 31, 2018, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $18.4 million in collateral with our counterparties. See "Credit Ratings" below and Note 13.

In October 2017, we entered into a 20-year operating lease agreement for our new headquarters location in Portland, Oregon. Our existing headquarters lease expires in 2020, and payments under the new lease are expected to commence in 2020. Total estimated base rent payments over the life of the lease are approximately $160.0 million. We have the option to extend the term of the lease for two additional seven-year periods. See Note 10.

Other items that may have a significant impact on our liquidity and capital resources include pension contribution requirements, bonus depreciation, environmental expenditures, gas storage, dividend policy, and off-balance sheet arrangements. For additional information, see Part II, Item 7 "Financial Condition" in our 2017 Form 10-K.

Gas Storage

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

Consolidated

Table of Contents

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 anticipated amounts of 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 March 31, 2018, our utility had $50.0 million short-term debt outstanding, compared to none outstanding at March 31, 2017, due to the sale of commercial paper. The weighted average interest rate on short-term debt outstanding at March 31, 2018 was 2.0%.

Credit Agreements
We have a $300.0 million credit agreement, with a feature that allows us to request increases in the total commitment amount, up to a maximum of $450.0 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 March 31, 2018 as follows:
In millions

Lender rating, by category	Loan Commitment
AA/Aa	$ 201
A/A1	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 $100.0 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 March 31, 2018 or 2017. 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 March 31, 2018 and 2017, with consolidated indebtedness to total capitalization ratios of 51.1% and 45.1%, respectively.

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

Credit Ratings

Our credit ratings are a factor of our liquidity, potentially affecting our access to 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	Negative

In January 2018, Moody's revised our ratings outlook from "stable" to "negative". This revision was a result of their view of the potential negative impact that the TCJA could have on our regulated utility cash flow metrics. We expect the elimination of bonus

39

Table of Contents

depreciation on regulated utilities will increase cash taxes in the near term. However, we expect to see a net increase in cash flows as a result of the TCJA over the longer term as taxes are a pass through to customers and lower deferred tax liabilities are expected to increase regulatory returns.

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

In March 2018, we retired $22.0 million of FMBs with a coupon rate of 6.60%. No other debt was retired or issued in the three months ended March 31, 2018. Over the next twelve months, $75.0 million of FMBs with a coupon rate of 1.545% will mature in December 2018.

See Part II, Item 7, "Financial Condition—Contractual Obligations" in our 2017 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 or loss, changes in working capital requirements, and other cash and non-cash adjustments to operating results.

Operating activity highlights include:

	Three Months Ended March 31,		
In thousands	2018	2017	YTD Change
Cash provided by operating activities	$104,521	$145,166	$(40,645)

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. The significant factors contributing to the $40.6 million decrease in cash flows provided by operating activities were as follows:

- a net decrease of $9.6 million from changes in working capital related to receivables, inventories, and accounts payable reflecting warmer than average weather in 2018 compared to the prior period;
- a decrease of $9.9 million in cash flow benefits from changes in deferred gas cost balances due to a decrease in natural gas prices compared to the prior year; and
- a decrease of $6.8 million due to $9.8 million of income taxes paid in 2018 compared to $3.0 million in the prior period;

During the three months ended March 31, 2018, we contributed $1.7 million to our utility's qualified defined benefit pension plan, compared to $3.2 million for the same period in 2017. The amount and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. For additional information, see Note 8.

Bonus depreciation of 50% was available for federal and Oregon purposes for most of 2017, which reduced taxable income and provided cash flow benefits. As a result of the TCJA, bonus depreciation was eliminated for property acquired after September 27, 2017. Accordingly, we do not anticipate similar cash flow benefits related to bonus depreciation in the future.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For additional information, see Part II, Item 7 "Financial Condition—Contractual Obligations" and Note 14 in our 2017 Form 10-K.

Investing Activities
Investing activity highlights include:

	Three Months Ended March 31,		
In thousands	2018	2017	YTD Change
Total cash used in investing activities	$(57,488)	$(38,826)	$(18,662)
Capital expenditures	(57,431)	(38,924)	(18,507)

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. The $18.7 million increase in cash used in investing activities was primarily due to higher capital expenditures primarily related to system reinforcement and customer growth, as well as our North Mist Gas Storage Expansion Project.

Over the five-year period 2018 through 2022, capital expenditures are estimated to be between $750 and $850 million. This includes investments ranging from $650 to $700 million for core utility capital expenditures that will support continued customer growth, distribution system maintenance and improvements, technology investments, and utility gas storage facility

Table of Contents

maintenance. In addition, the five year period includes $20 to $30 million of additional investments to complete the North Mist gas storage facility expansion in 2018, and investments of $60 to $70 million related to planned upgrades and refurbishments to utility storage facilities and resource centers. Most of the required funds for these investments are expected to be internally generated over the five-year period, with short-term and long-term debt, and equity providing liquidity.

Included in the five-year period, 2018 utility capital expenditures are estimated to be between $190 and $220 million, including $20 to $30 million to complete construction of our North Mist gas storage facility expansion. We expect to invest less than $5 million in non-utility capital investments for gas storage and other activities in 2018. Additional spend for gas storage and other investments during or after 2018 are expected to be paid from working capital and additional equity contributions from NW Natural as needed.

Financing Activities

Financing activity highlights include:

	Three Months Ended March 31,		
In thousands	2018	2017	YTD Change
Total cash used in financing activities	$(39,290)	$(69,222)	$29,932
Change in short-term debt	(4,200)	(53,300)	49,100
Change in long-term debt	(22,000)	—	(22,000)

THREE MONTHS ENDED MARCH 31, 2018 COMPARED TO MARCH 31, 2017. The $29.9 million decrease in cash used in financing activities was primarily due to lower repayments of $49.1 million of short-term debt compared to the prior period, partially offset by a $22.0 million repayment of long-term debt in March 2018.

Ratios of Earnings to Fixed Charges

For the three months ended March 31, 2018 our ratio of earnings to fixed charges was 5.74. For the twelve months ended March 31, 2018 and December 31, 2017, our earnings were insufficient to cover our fixed charges by $96.6 million and $86.4 million, respectively, as a result of the non-cash impairment of long-lived assets at the Gill Ranch Facility recorded during December 2017. For purposes of this calculation, earnings consist of net income before income taxes plus fixed charges, whereby 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 2017 Form 10-K. At March 31, 2018, our total estimated liability related to environmental sites is $123.4 million. See "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs" in our 2017 Form 10-K and Note 14.

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 our 2017 Form 10-K with respect to the application of critical accounting policies and estimates other than those associated with the new revenue recognition standard as discussed in Note 2 and Note 5. See Part II, Item 7, "Application of Critical Accounting Policies and Estimates," in the 2017 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.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price 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 three months ended March 31, 2018. For additional information, see Part II, Item 1A, "Risk Factors" in this report and Part II, Item 7A, "Quantitative and Qualitative Disclosures about Market Risk" in the 2017 Form 10-K.

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 March 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

Table of Contents

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 14 and those proceedings disclosed and incorporated by reference in Part I, Item 3, "Legal Proceedings" in our 2017 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 2017 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 March 31, 2018:

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
01/01/18-01-31/18	—	$ —	—	—
02/01/18-02/28/18	—	—	—	—
03/01/18-03/31/18	10,782	53.57	—	—
Total	10,782	53.57	2,124,528	$ 16,732,648

(1) During the quarter ended March 31, 2018, no shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. However, 10,782 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended March 31, 2018, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) During the quarter ended March 31, 2018, no shares of our common stock were repurchased pursuant to our Board-Approved share repurchase program. For more information on this program, refer to Note 5 in our 2017 Form 10-K.

ITEM 6. EXHIBITS

See Exhibit Index below, which is incorporated by reference herein.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Quarterly Report on Form 10-Q
For the Quarter Ended March 31, 2018

Exhibit Index

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 March 31, 2018, 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.

Table of Contents

SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)
Dated: May 8, 2018

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