NORTHWEST NATURAL GAS CO
Form 10-Q
August 07, 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 June 30, 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 July 27, 2018, 28,800,482 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended June 30, 2018

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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 and financial 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;
- asset dispositions and outcomes 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.

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

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ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2018	2017	2018	2017
Operating revenues	$124,567	$134,476	$388,202	$430,200
Operating expenses:				
Cost of gas	42,053	53,005	150,159	196,616
Operations and maintenance	38,028	34,997	77,551	72,443
Environmental remediation	1,882	2,611	6,506	9,565
General taxes	7,729	7,204	17,203	15,883
Revenue taxes	4,780	—	17,209	—
Depreciation and amortization	21,147	20,224	42,022	40,177
Other operating expenses	679	—	1,532	—
Total operating expenses	116,298	118,041	312,182	334,684
Income from operations	8,269	16,435	76,020	95,516
Other income (expense), net	7	(340)	(827)	(763)
Interest expense, net	8,771	9,473	18,045	19,103
Income (loss) before income taxes	(495)	6,622	57,148	75,650
Income tax (benefit) expense	(156)	2,547	15,476	30,178
Net income (loss) from continuing operations	(339)	4,075	41,672	45,472
Loss from discontinued operations, net of tax	(659)	(1,346)	(1,133)	(2,433)
Net income (loss)	(998)	2,729	40,539	43,039
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $56 and $88 for the three months ended and $111 and $177 for the six months ended June 30, 2018 and 2017, respectively	153	137	307	273
Comprehensive income (loss)	$(845)	$2,866	$40,846	$43,312
Average common shares outstanding:				
Basic	28,791	28,648	28,772	28,641
Diluted	28,791	28,717	28,825	28,722
Earnings (loss) from continuing operations per share of common stock:				
Basic	$(0.01)	$0.14	$1.45	$1.58
Diluted	(0.01)	0.14	1.45	1.58
Loss from discontinued operations per share of common stock:				
Basic	$(0.02)	$(0.04)	$(0.04)	$(0.08)
Diluted	(0.02)	(0.04)	(0.04)	(0.08)
Earnings (loss) per share of common stock:				
Basic	$(0.03)	$0.10	$1.41	$1.50
Diluted	(0.03)	0.10	1.41	1.50
Dividends declared per share of common stock	0.4725	0.4700	0.9450	0.9400

See Notes to Unaudited Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2018	June 30, 2017	December 31, 2017
Assets:			
Current assets:			
Cash and cash equivalents	$8,755	$20,854	$3,472
Accounts receivable	31,512	30,778	66,236
Accrued unbilled revenue	13,995	13,896	62,381
Allowance for uncollectible accounts	(657)	(845)	(956)
Regulatory assets	41,092	37,504	45,781
Derivative instruments	2,044	1,530	1,735
Inventories	43,109	57,264	47,577
Gas reserves	16,579	16,072	15,704
Other current assets	11,672	13,028	24,949
Discontinued operations current assets (Note 15)	12,743	1,923	3,057
Total current assets	180,844	192,004	269,936
Non-current assets:			
Property, plant, and equipment	3,298,856	3,098,112	3,204,635
Less: Accumulated depreciation	984,998	942,558	960,477
Total property, plant, and equipment, net	2,313,858	2,155,554	2,244,158
Gas reserves	75,362	92,020	84,053
Regulatory assets	339,177	348,284	356,608
Derivative instruments	1,077	162	1,306
Other investments	64,854	68,885	66,363
Other non-current assets	11,588	3,164	6,505
Discontinued operations non-current assets (Note 15)	—	205,081	10,817
Total non-current assets	2,805,916	2,873,150	2,769,810
Total assets	$2,986,760	$3,065,154	$3,039,746

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2018	June 30, 2017	December 31, 2017
Liabilities and equity:			
Current liabilities:			
Short-term debt	$47,100	$—	$54,200
Current maturities of long-term debt	74,785	61,991	96,703
Accounts payable	70,551	95,126	111,021
Taxes accrued	6,916	6,906	18,883
Interest accrued	6,652	5,966	6,773
Regulatory liabilities	34,275	28,041	34,013
Derivative instruments	11,744	4,734	18,722
Other current liabilities	32,935	31,015	39,942
Discontinued operations current liabilities (Note 15)	12,922	1,303	1,593
Total current liabilities	297,880	235,082	381,850
Long-term debt	683,895	658,118	683,184
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	281,028	577,176	270,526
Regulatory liabilities	602,294	359,205	586,093
Pension and other postretirement benefit liabilities	218,061	219,718	223,333
Derivative instruments	3,913	3,466	4,649
Other non-current liabilities	140,163	134,793	135,292
Discontinued operations - non-current liabilities (Note 15)	—	12,167	12,043
Total deferred credits and other non-current liabilities	1,245,459	1,306,525	1,231,936
Commitments and contingencies (Note 14)			
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 28,800, 28,662, and 28,736 at June 30, 2018 and 2017, and December 31, 2017, respectively	452,195	444,058	448,865
Retained earnings	315,462	428,049	302,349
Accumulated other comprehensive loss	(8,131)	(6,678)	(8,438)
Total equity	759,526	865,429	742,776
Total liabilities and equity	$2,986,760	$3,065,154	$3,039,746

See Notes to Unaudited Consolidated Financial Statements

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

	Six Months Ended June 30,	
In thousands	2018	2017
Operating activities:		
Net Income	$40,539	$43,039
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	42,022	40,177
Regulatory amortization of gas reserves	7,816	8,031
Deferred income taxes	11,227	22,170
Qualified defined benefit pension plan expense	2,876	2,615
Contributions to qualified defined benefit pension plans	(5,570)	(7,250)
Deferred environmental expenditures, net	(7,330)	(6,817)
Amortization of environmental remediation	6,506	9,565
Regulatory revenue deferral from the TCJA	9,212	—
Other	810	1,128
Changes in assets and liabilities:		
Receivables, net	79,332	85,250
Inventories	4,803	(3,501)
Income taxes	(11,967)	(5,243)
Accounts payable	(26,613)	(21,849)
Interest accrued	(121)	—
Deferred gas costs	4,787	15,325
Other, net	3,623	8,243
Discontinued operations	700	3,348
Cash provided by operating activities	162,652	194,231
Investing activities:		
Capital expenditures	(102,370)	(94,333)
Other	195	(404)
Discontinued operations	(283)	15
Cash used in investing activities	(102,458)	(94,722)
Financing activities:		
Repurchases related to stock-based compensation	—	(2,034)
Proceeds from stock options exercised	45	1,309
Long-term debt retired	(22,000)	—
Change in short-term debt	(7,100)	(53,300)
Cash dividend payments on common stock	(25,577)	(26,919)
Other	(279)	(1,232)
Cash used in financing activities	(54,911)	(82,176)
Increase in cash and cash equivalents	5,283	17,333
Cash and cash equivalents, beginning of period	3,472	3,521
Cash and cash equivalents, end of period	$8,755	$20,854

Supplemental disclosure of cash flow information:

Interest paid, net of capitalization	$17,117	$18,011
Income taxes paid	13,347	9,081

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

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies we directly or indirectly control, either through majority ownership or otherwise. Our regulated local gas distribution business, referred to as the utility segment, is our core operating business and serves residential, commercial, and industrial customers in Oregon and southwest Washington. The other category primarily includes the non-utility portion of our Mist gas storage facility that provides storage services for utilities, gas marketers, electric generators, and large industrial users from facilities located in Oregon. In addition, we have investments and other non-utility activities reported 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), which is presented as a discontinued operation;
- Northwest Energy Corporation (Energy Corp);
  - NWN Gas Reserves LLC (NWN Gas Reserves);
- NNG Financial Corporation (NNG Financial);

- NW Natural Water Company, LLC (NWN Water);
  - FWC Merger Sub, Inc.;
  - Cascadia Water, LLC (Cascadia);
- Northwest Natural Holding Company (NWN Holding); and
  - NWN Merger Sub, Inc. (NWN Holdco Sub).

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 NNG 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 the non-utility portion of our Mist gas storage facility 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), taking into consideration the changes mentioned below in this Note 1 and in Notes 4 and 15. 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.

During the second quarter of 2018, we moved forward with our long-term strategic plans, which include a shift away from our merchant gas storage business. In June 2018, NWN Gas Storage, our wholly-owned subsidiary, entered into a Purchase and Sale Agreement that provides for the sale of all of the membership interests in its wholly-owned subsidiary, Gill Ranch, subject to various regulatory approvals and closing conditions. We have concluded that the pending sale of Gill Ranch qualifies as assets and liabilities held for sale and discontinued operations. As such, for all periods presented, the results of Gill Ranch have been presented as a discontinued operation on the consolidated statements of comprehensive income and cash flows, and the assets and liabilities associated with Gill Ranch have been classified as discontinued operations assets and liabilities on the consolidated balance sheets. See Note 15 for additional information. Additionally, we reevaluated our reportable segments and concluded that the remaining gas storage activities no longer meet the requirements to be separately reported as a segment. The non-utility portion of our Mist gas storage facility is now reported as other, and all prior periods reflect this change. See Note 4, which provides segment information. These reclassifications had no effect on our prior year's consolidated results of operations, financial condition, or cash flows.

Our notes to the consolidated financial statements reflect the activity of our continuing operations for all periods presented, unless otherwise noted. Note 15 provides information regarding our discontinued operations.

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 six months ended June 30, 2018 other than those incorporated in Note 5 and Note 15 relating to revenue and discontinued operations, respectively. The following are current updates to certain critical accounting policy estimates and new accounting standards.

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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.

Amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	June 30,		December 31,
In thousands	2018	2017	2017
Current:			
Unrealized loss on derivatives(1)	$11,744	$4,625	$18,712
Gas costs	273	859	154
Environmental costs(2)	5,594	6,724	6,198
Decoupling(3)	10,232	12,136	11,227
Income taxes	2,217	4,378	2,218
Other(4)	11,032	8,782	7,272
Total current	$41,092	$37,504	$45,781
Non-current:			
Unrealized loss on derivatives(1)	$3,913	$3,466	$4,649
Pension balancing(5)	67,527	55,358	60,383
Income taxes	19,267	36,591	19,991
Pension and other postretirement benefit liabilities	171,186	176,136	179,824
Environmental costs(2)	65,156	64,008	72,128
Gas costs	28	87	84
Decoupling(3)	1,636	1,993	3,970
Other(4)	10,464	10,645	15,579
Total non-current	$339,177	$348,284	$356,608

	Regulatory Liabilities		
	June 30,		December 31,
In thousands	2018	2017	2017
Current:			
Gas costs	$20,906	$15,708	$14,886
Unrealized gain on derivatives(1)	1,938	1,459	1,674
Decoupling(3)	2,153	134	322
Other(4)	9,278	10,740	17,131
Total current	$34,275	$28,041	$34,013
Non-current:			
Gas costs	$3,460	$2,719	$4,630
Unrealized gain on derivatives(1)	1,077	162	1,306
Decoupling(3)	410	—	957
Income taxes(6)	222,734	—	213,306
Accrued asset removal costs(7)	370,245	350,828	360,929
Other(4)	4,368	5,496	4,965
Total non-current	$602,294	$359,205	$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) Balances 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) This balance represents estimated amounts associated with the Tax Cuts and Jobs Act. See Note 9.
(7) Estimated costs of removal on certain regulated properties are collected through rates.

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We believe all costs incurred and deferred at June 30, 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). ASUs 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 and six months ended June 30, 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 and six months ended June 30, 2017, $1.3 million and $2.6 million of expense was reclassified from operations and maintenance expense and included in other income (expense), net, respectively.

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 for the three and six months ended June 30, 2018 would have been $119.8 million and $371.0 million, compared to the reported amounts of $124.6 million and $388.2 million under the new revenue standard, respectively. Similarly, absent the impact of the new revenue standard, our operating expenses would have been $111.5 million and $295.0 million, compared to the reported amounts of $116.3 million and $312.2 million under the new revenue standard for the three and six months ended June 30, 2018, respectively. The effect of the change was an increase in both operating revenues and operating expenses of $4.8 million and $17.2 million for the three and six months ended June 30, 2018, respectively, 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 and six months ended June 30, 2018, we recognized $4.8 million and $17.2 million in revenue taxes in operating revenues and operating expenses, respectively. In comparison, for the three and six months ended June 30, 2017, we recognized $5.6 million and $19.3 million in revenue taxes, of which $3.2 million and $11.0 million were recorded in operating revenues and $2.4 million and $8.3 million were recorded on the balance sheet, respectively. 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.

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3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except 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 (loss) from continuing operations per share are calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2018	2017	2018	2017
Net income (loss) from continuing operations	$(339)	$4,075	$41,672	$45,472
Average common shares outstanding - basic	28,791	28,648	28,772	28,641
Additional shares for stock-based compensation plans (See Note 6)	—	69	53	81
Average common shares outstanding - diluted	28,791	28,717	28,825	28,722
Earnings (loss) from continuing operations per share of common stock - basic	$(0.01)	$0.14	$1.45	$1.58
Earnings (loss) from continuing operations per share of common stock - diluted	$(0.01)	$0.14	$1.45	$1.58
Additional information:				
Antidilutive shares	53	32	10	21

4. SEGMENT INFORMATION

We primarily operate in one reportable business segment, which is our local gas distribution business and which is referred to as the utility segment. During the second quarter of 2018, we moved forward with our long-term strategic plans, which include a shift away from our merchant gas storage business, by entering into a Purchase and Sale Agreement that provides for the sale of all of the membership interests in Gill Ranch, subject to various regulatory approvals and closing conditions. As such, we reevaluated our reportable segments and concluded that the gas storage activities no longer meet the requirements of a reportable segment. Our ongoing, non-utility gas storage activities, which include our interstate storage and optimization activities at our Mist gas storage facility, are now reported as other. We also have other investments and business activities not specifically related to our utility segment, which are aggregated and reported as other. We refer to our local gas distribution business as the utility and all other activities as non-utility.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC.

Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers' end-use facilities for a fee, which is approved by the OPUC or WUTC. As of December 31, 2017, approximately 89% of our customers are located in Oregon and 11% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. A small amount of utility margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors we serve include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery, and textiles; the manufacture of asphalt, concrete, and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation.

In addition to our local gas distribution business, our utility segment also includes the utility portion of our Mist underground storage facility, our North Mist gas storage expansion in Oregon, and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp.

Other

We have non-utility investments and other business activities, which are aggregated and reported as other. Other includes NWN Gas Storage, a wholly-owned subsidiary of NWN Energy, and the non-utility portion of our Mist facility in Oregon and third-party

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asset management services. Earnings from non-utility assets at our Mist facility are primarily related to firm storage capacity revenues. Earnings from the Mist facility also include revenue, net of amounts shared with utility customers, from management of utility assets at Mist and upstream pipeline capacity when not needed to serve utility customers. Under the Oregon sharing mechanism, we retain 80% of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33% of the pre-tax income when the costs have been included in utility rates. The remaining 20% and 67%, respectively, are recorded to a deferred regulatory account for crediting back to utility customers.

Other also 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 subsidiaries FWC Merger Sub, Inc. and Cascadia, 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 holding company reorganization of NW Natural through its wholly-owned subsidiary NWN Holdco Sub.

All prior period amounts have been retrospectively adjusted to reflect the change in our reportable segments and the designation of Gill Ranch as a discontinued operation.

Inter-segment transactions were immaterial for the periods presented. The following table presents summary financial information concerning the reportable segments of our continuing operations. See Note 15 for information regarding our discontinued operation, Gill Ranch Storage.

	Three Months Ended June 30,		
In thousands	Utility	Other	Total
2018			
Operating revenues	$118,515	$6,052	$124,567
Depreciation and amortization	20,766	381	21,147
Income from operations	4,545	3,724	8,269
Net income (loss) from continuing operations	(2,970)	2,631	(339)
Capital expenditures	43,801	1,239	45,040
2017			
Operating revenues	$130,095	$4,381	$134,476
Depreciation and amortization	19,894	330	20,224
Income from operations	13,158	3,277	16,435
Net income from continuing operations	2,137	1,938	4,075
Capital expenditures	54,265	1,142	55,407

	Six Months Ended June 30,		
In thousands	Utility	Other	Total
2018			
Operating revenues	$376,448	$11,754	$388,202
Depreciation and amortization	41,309	713	42,022
Income from operations	69,301	6,719	76,020
Net income from continuing operations	36,913	4,759	41,672
Capital expenditures	100,695	1,675	102,370
Total assets at June 30, 2018[1]	2,907,724	66,293	2,974,017
2017			
Operating revenues	$422,821	$7,379	$430,200

Depreciation and amortization	39,518	659	40,177
Income from operations	90,285	5,231	95,516
Net income from continuing operations	42,329	3,143	45,472
Capital expenditures	93,119	1,214	94,333
Total assets at June 30, 2017[1]	2,792,011	66,139	2,858,150
Total assets at December 31, 2017[1]	2,961,326	64,546	3,025,872

(1) Total assets exclude assets related to discontinued operations of $12.7 million, $207.0 million, and $13.9 million as of June 30, 2018, June 30, 2017, and December 31, 2017, respectively.

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Utility Margin

Utility margin is a financial measure used by our chief operating decision maker (CODM) 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 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 CODM in assessing the performance of the utility segment.

The following table presents additional segment information concerning utility margin:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2018	2017	2018	2017
Utility margin calculation:				
Utility operating revenues	$118,515	$130,095	$376,448	$422,821
Less: Utility cost of gas	42,107	53,005	150,271	196,616
Environmental remediation expense	1,882	2,611	6,506	9,565
Revenue taxes[1]	4,780	—	17,209	—
Utility margin	$69,746	$74,479	$202,462	$216,640

(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 from continuing operations:

	Three months ended June 30, 2018		
In thousands	Utility	Other	Total
Local gas distribution revenue	$114,725	$—	$114,725
Gas storage revenue, net	—	2,736	2,736
Asset management revenue, net	—	2,140	2,140
Appliance retail center revenue	—	1,176	1,176
Revenue from contracts with customers	114,725	6,052	120,777
Alternative revenue	3,663	—	3,663
Leasing revenue	127	—	127
Total operating revenues	$118,515	$6,052	$124,567

	Six months ended June 30, 2018		
In thousands	Utility	Other	Total
Local gas distribution revenue	$372,954	$—	$372,954

Gas storage revenue, net	—	5,314	5,314
Asset management revenue, net	—	3,719	3,719
Appliance retail center revenue	—	2,721	2,721
Revenue from contracts with customers	372,954	11,754	384,708
Alternative revenue	3,291	—	3,291
Leasing revenue	203	—	203
Total operating revenues	$376,448	$11,754	$388,202

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 June 30, 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.

Other
Gas storage revenue. Our gas storage activity includes the non-utility portion of our Mist facility, which is 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. 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. Variable revenues earned above guaranteed amounts 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 June 30, 2018, unrecognized revenue for the fixed component of the transaction price related to our gas storage and asset management revenue was approximately $43.4 million. Of this amount, approximately $8.1 million will be recognized during the remainder of 2018, $10.2 million in 2019, $8.5 million in 2020, $7.5 million in 2021, $4.3 million in 2022 and $4.8 million thereafter.

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.

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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 six months ended June 30, 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 June 30, 2018 and therefore no expense was recognized for the 2018 award. We will calculate the grant date fair value and recognize expense once the final performance factor has been approved.

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 June 30, 2018, there was $2.1 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 six months ended June 30, 2018, 26,087 RSUs were granted under the LTIP with a weighted-average grant date fair value of $55.16 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. Generally, 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 June 30, 2018, there was $3.3 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2022.

7. DEBT

Short-Term Debt

At June 30, 2018, we had short-term debt of $47.1 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 June 30, 2018, our commercial paper had a maximum remaining maturity of 12 days and average remaining maturity of 7 days.

Long-Term Debt
At June 30, 2018, we had long-term debt of $758.7 million, which included $6.0 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.

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

	June 30,		December 31,
In thousands	2018	2017	2017
Gross long-term debt	$764,700	$726,700	$786,700
Unamortized debt issuance costs	(6,020)	(6,591)	(6,813)
Carrying amount	$758,680	$720,109	$779,887
Estimated fair value(1)	$792,623	$791,885	$853,339

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

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
In thousands	2018	2017	2018	2017	2018	2017	2018	2017
Service cost	$1,807	$1,870	$79	$99	$3,614	$3,740	$159	$197
Interest cost	4,183	4,472	241	274	8,366	8,944	482	548
Expected return on plan assets	(5,150)	(5,112)	—	—	(10,301)	(10,225)	—	—
Amortization of prior service costs	10	31	(117)	(117)	21	63	(234)	(234)
Amortization of net actuarial loss	4,524	3,622	112	139	9,047	7,243	222	277
Net periodic benefit cost	5,374	4,883	315	395	10,747	9,765	629	788
Amount allocated to construction	(685)	(1,558)	(28)	(135)	(1,367)	(3,079)	(55)	(267)
Amount deferred to regulatory balancing account[(1)]	(2,747)	(1,508)	—	—	(5,503)	(3,035)	—	—
Net amount charged to expense	$1,942	$1,817	$287	$260	$3,877	$3,651	$574	$521

(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 June 30,		Six Months Ended June 30,	
In thousands	2018	2017	2018	2017
Beginning balance	$(8,284)	$(6,815)	$(8,438)	$(6,951)
Amounts reclassified from AOCL:				
Amortization of actuarial losses	209	225	418	450
Total reclassifications before tax	209	225	418	450
Tax (benefit) expense	(56)	(88)	(111)	(177)
Total reclassifications for the period	153	137	307	273
Ending balance	$(8,131)	$(6,678)	$(8,131)	$(6,678)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

For the six months ended June 30, 2018, we made cash contributions totaling $5.6 million to our qualified defined benefit pension plans. We expect further plan contributions of $10.0 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 $3.5 million and $2.8 million for the six months ended June 30, 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Dollars in thousands	2018	2017	2018	2017
Income taxes at statutory rates (federal and state)	$(135)	$2,603	$15,233	$29,912
Increase (decrease):				
Differences required to be flowed-through by regulatory commissions	(14)	66	835	1,584
Other, net	(7)	(122)	(592)	(1,318)
Total provision for income taxes on continuing operations	$(156)	$2,547	$15,476	$30,178
Effective tax rate for continuing operations	31.5 %	38.5 %	27.1 %	39.9 %

The effective income tax rate for the three and six months ended June 30, 2018 compared to the same periods 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 June 30, 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 yet certain 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 June 30, 2018, a regulatory liability of $9.4 million has been recorded including accrued interest to reflect this estimated revenue deferral.

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10. PROPERTY, PLANT, AND EQUIPMENT

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

	June 30,		December 31,
In thousands	2018	2017	2017
Utility plant in service	$3,035,089	$2,901,791	$2,975,217
Utility construction work in progress	192,496	127,383	159,924
Less: Accumulated depreciation	966,766	925,589	942,879
Utility plant, net	2,260,819	2,103,585	2,192,262
Non-utility plant in service	65,743	63,964	65,372
Non-utility construction work in progress	5,528	4,974	4,122
Less: Accumulated depreciation	18,232	16,969	17,598
Non-utility plant, net (1)	53,039	51,969	51,896
Total property, plant, and equipment	$2,313,858	$2,155,554	$2,244,158
Capital expenditures in accrued liabilities (2)	$22,112	$42,574	$34,761

(1) Previously reported non-utility balances were restated due to the assets and liabilities associated with Gill Ranch now being classified as discontinued operations assets and liabilities on the consolidated balance sheets. See Note 15 for further discussion.

(2) Previously reported capital expenditures in accrued liabilities were restated due to the assets and liabilities associated with Gill Ranch now being classified as discontinued operations assets and liabilities on the consolidated balance sheets. Capital expenditures in accrued liabilities related to Gill Ranch were approximately $0.3 million, $0.1 million, and $0.2 million as of June 30, 2018, June 30, 2017, and December 31, 2017, respectively.

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 $7.6 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 June 30, 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 approximately $188 million through our gas reserves program in the Jonah Field located in Wyoming as of June 30, 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 approximately $178 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.

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The following table outlines our net gas reserves investment:

	June 30,		December 31,
In thousands	2018	2017	2017
Gas reserves, current	$16,579	$16,072	$ 15,704
Gas reserves, non-current	170,958	171,464	171,832
Less: Accumulated amortization	95,596	79,444	87,779
Total gas reserves(1)	91,941	108,092	99,757
Less: Deferred taxes on gas reserves	20,381	31,074	22,712
Net investment in gas reserves	$71,560	$77,018	$ 77,045

(1) Our net investment in additional wells included in total gas reserves was $5.5 million, $6.3 million and $5.8 million at June 30, 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.

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 June 30, 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, net of amounts shared with utility customers.

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Notional Amounts

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

In thousands	June 30, 2018	June 30, 2017	December 31, 2017
Natural gas (in therms):			
Financial	473,900	490,780	429,100
Physical	724,450	495,751	520,268
Foreign exchange	$7,804	$7,788	$ 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.

Unrealized and Realized Gain/Loss

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

	Three Months Ended June 30,			
	2018		2017	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$2,658	$ (56)	$(5,172)	$ 216
Operating revenues	391	—	(109)	—
Amounts deferred to regulatory accounts on balance sheet	(2,915)	56	5,263	(216)
Total gain (loss) in pre-tax earnings	$134	$ —	$(18)	$ —

	Six Months Ended June 30,			
	2018		2017	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$(3,089)	$ (210)	$(16,515)	$ 224
Operating revenues	164	—	(1,277)	—
Amounts deferred to regulatory accounts on balance sheet	2,980	210	17,347	(224)
Total gain (loss) in pre-tax earnings	$55	$ —	$(445)	$ —

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 $4.7 million and $13.7 million for the three and six months ended June 30, 2018, respectively, from the settlement of natural gas financial derivative contracts. Whereas, we realized net gains of $0.3 million and remained flat for the three and six months ended June 30, 2017, respectively. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments
No collateral was posted with or by our counterparties as of June 30, 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

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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 $14.3 million at June 30, 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	$ —	$ —	$ —	$ (3,605)	$ (11,211)
Without Adequate Assurance Calls	—	—	—	(3,605)	(6,987)

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 physical and financial derivative position would result in an asset of $2.5 million and a liability of $15.0 million as of June 30, 2018, an asset of $0.9 million and a liability of $7.4 million as of June 30, 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 June 30, 2018. Using significant other observable or Level 2 inputs, the net fair value was a liability of $12.5 million, $6.5 million, and $20.3 million as of June 30, 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 six months ended June 30, 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. 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		
	June 30,		December 31,	June 30,		December 31,
In thousands	2018	2017	2017	2018	2017	2017
Portland Harbor site:						
Gasco/Siltronic Sediments	$2,174	$1,485	$ 2,683	$45,330	$43,376	$45,346
Other Portland Harbor	1,444	1,435	1,949	3,871	3,906	4,163
Gasco/Siltronic Upland site	9,947	9,441	13,422	45,578	49,319	47,835
Central Service Center site	25	31	25	—	—	—
Front Street site	906	829	1,009	10,683	10,788	10,757
Oregon Steel Mills	—	—	—	179	179	179
Total	$14,496	$13,221	$ 19,088	$105,641	$107,568	$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 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 $47.5 million to $350 million. We have recorded a liability of $47.5 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

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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 $1.1 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.

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

	June 30,		December 31,
In thousands	2018	2017	2017
Deferred costs and interest [1]	$46,862	$50,131	$45,546
Accrued site liabilities [2]	119,712	120,485	126,950
Insurance proceeds and interest	(95,824)	(99,884)	(94,170)
Total regulatory asset deferral[1]	$70,750	$70,732	$78,326
Current regulatory assets[3]	5,594	6,724	6,198
Long-term regulatory assets[3]	65,156	64,008	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.

15. DISCONTINUED OPERATIONS

On June 20, 2018, NWN Gas Storage, our wholly owned subsidiary, entered into a Purchase and Sale Agreement (the Agreement) that provides for the sale by NWN Gas Storage of all of the membership interests in Gill Ranch. Gill Ranch owns a 75% interest in the natural gas storage facility located near Fresno, California known as the Gill Ranch Gas Storage Facility. Pacific Gas and Electric Company (PG&E) owns the remaining 25% interest in the Gill Ranch Gas Storage Facility.

The Agreement provides for an initial cash purchase price of $25.0 million (subject to a working capital adjustment), plus potential additional payments to NWN Gas Storage of up to $26.5 million in the aggregate if Gill Ranch achieves certain economic performance levels for the first three full gas storage years (April 1 of one year through March 31 of the following year) occurring after the closing and the remaining portion of the gas storage year during which the closing occurs.

We expect the transaction to close within 12 months of signing and in 2019. The closing of the transaction is subject to approval by the California Public Utilities Commission (CPUC) and other customary closing conditions.

As a result of our strategic shift away from merchant gas storage and the significance of Gill Ranch's financial results in 2017, we have concluded that the pending sale of Gill Ranch qualifies as assets and liabilities held for sale and discontinued

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operations. As such, the assets and liabilities associated with Gill Ranch have been classified as discontinued operations assets and discontinued operations liabilities, respectively, and, the results of Gill Ranch are presented separately, net of tax, as discontinued operations from the results of continuing operations for all periods presented. The expenses included in the results of discontinued operations are the direct operating expenses incurred by Gill Ranch that may be reasonably segregated from the costs of our continuing operations.

The following table presents the carrying amounts of the major components of Gill Ranch that are classified as discontinued operations assets and liabilities on our consolidated balance sheets:

	June 30,		December 31,
In thousands	2018	2017	2017
Assets:			
Accounts receivable	$497	$1,130	$ 2,126
Inventories	646	402	396
Other current assets	413	391	535
Property, plant, and equipment	10,948	235,556	10,816
Less: Accumulated depreciation	6	30,526	—
Other non-current assets	245	51	1
Discontinued operations - current assets [1]	12,743	1,923	3,057
Discontinued operations - non-current assets [1]	—	205,081	10,817
Total discontinued operations assets	$12,743	$207,004	$ 13,874
Liabilities:			
Accounts payable	$572	$635	$ 1,287
Other current liabilities	436	668	306
Other non-current liabilities	11,914	12,167	12,043
Discontinued operations - current liabilities [1]	12,922	1,303	1,593
Discontinued operations - non-current liabilities [1]	—	12,167	12,043
Total discontinued operations liabilities	$12,922	$13,470	$ 13,636

(1) The total assets and liabilities of Gill Ranch are classified as current as of June 30, 2018 because it is probable that the sale will be completed within one year.

The following table presents the operating results of Gill Ranch, which was reported within our gas storage segment historically, and is presented net of tax on our consolidated statements of comprehensive income:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2018	2017	2018	2017
Revenues	$1,006	$1,762	$2,083	$3,361
Expenses:				
Operations and maintenance	1,554	2,251	2,590	3,921
Depreciation and amortization	108	1,131	218	2,263
Other expenses and interest	239	604	814	1,196
Total expenses	1,901	3,986	3,622	7,380
Loss from discontinued operations before income taxes	(895)	(2,224)	(1,539)	(4,019)
Income tax benefit	236	878	406	1,586
Loss from discontinued operations, net of tax	$(659)	$(1,346)	$(1,133)	$(2,433)

Loss from discontinued operations per share of common stock:				
Basic	$(0.02)	$(0.04)	$(0.04)	$(0.08)
Diluted	$(0.02)	$(0.04)	$(0.04)	$(0.08)

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

The following is management’s assessment of Northwest Natural Gas Company’s (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated results from continuing operations for the three and six months ended June 30, 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), which is presented as a discontinued operation;
- 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.;
- Cascadia Water, LLC;
- Northwest Natural Holding Company (NWN Holding); and
- NWN Merger Sub, Inc. (NWN Holdco Sub).

We primarily operate in one reportable business segment, which is our local gas distribution business and which is referred to as the utility segment. During the second quarter of 2018, we moved forward with our long-term strategic plans, which include a shift away from our merchant gas storage business, by entering into a Purchase and Sale Agreement that provides for the sale of all of the membership interests in Gill Ranch, subject to various regulatory approvals and closing conditions. As such, we reevaluated our reportable segments and concluded that the gas storage activities no longer meet the requirements of a reportable segment. Our ongoing, non-utility gas storage activities, which include our interstate storage and optimization activities at our Mist gas storage facility, are now reported as other. We also have other investments and business activities not specifically related to our utility segment, which are aggregated and reported as other. We refer to our local gas distribution business as the utility and all other activities as non-utility. See Note 4 for further discussion of our business segment 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.

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EXECUTIVE SUMMARY

We manage our business and strategic initiatives with a long-term view of providing natural gas service safely and reliably to customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See "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 June 30, 2018;
- invested $102.4 million in our distribution system and facilities for growth and reliability;
- continued constructing major elements of our North Mist Gas Storage Expansion Project and continue to target in-service during the fourth quarter of 2018;
- reached agreement on key items in the Oregon general rate case and filed an all-party settlement with the Commission;
- advanced our regulated water strategy with plans to acquire two small utilities in Washington state; and
- signed an agreement to sell our interest in the Gill Ranch natural gas storage facility located in California.

Key financial highlights include:

	Three Months Ended June 30,				
	2018		2017		$
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Net income (loss) from continuing operations	$(339)	$(0.01)	$4,075	$0.14	$(4,414)
Loss from discontinued operations, net of tax	(659)	(0.02)	(1,346)	(0.04)	687
Consolidated net income (loss)	$(998)	$(0.03)	$2,729	$0.10	$(3,727)
Utility margin	$69,746		$74,479		$(4,733)

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Net income from continuing operations decreased $4.4 million primarily due to the following factors:

- a $4.7 million decrease in utility margin due to the regulatory revenue deferral associated with the TCJA and warmer than average weather in 2018 compared to cooler than average weather in 2017, partially offset by customer growth; and
- a $3.0 million increase in operations and maintenance expense largely from payroll and benefits due to additional headcount and general salary increases; partially offset by
- a $2.7 million decrease in income tax expense due to changes in pre-tax income and the benefit from the decline of the U.S. federal corporate income tax rate to 21% in 2018 from 35% in the prior period. See additional discussion regarding "TCJA Timing Variance" below.

	Six Months Ended June 30,				
	2018		2017		$
In thousands, except per share data	Amount	Per Share	Amount	Per Share	Change
Net income from continuing operations	$41,672	$1.45	$45,472	$1.58	$(3,800)
Loss from discontinued operations, net of tax	(1,133)	(0.04)	(2,433)	(0.08)	1,300
Consolidated net income	$40,539	$1.41	$43,039	$1.50	$(2,500)
Utility margin	$202,462		$216,640		$(14,178)

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Net income from continuing operations decreased $3.8 million primarily due to the following factors:

- a $14.2 million decrease in utility margin due to a regulatory revenue deferral associated with the TCJA and colder than average weather in 2017, partially offset by customer growth; and

- a $5.1 million increase in operations and maintenance expense largely from payroll and benefits due to additional headcount and general salary increases as well as higher professional service costs; partially offset by
- a $14.7 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. See additional discussion regarding "TCJA Timing Variance" below.

TCJA Timing Variance

Results for both the quarter and six month periods ended June 30, 2018 were affected by a variance due to the timing difference between the regulatory revenue deferral associated with the TCJA and the tax expense benefit from the lower federal tax rate. On an annual basis we expect the deferral and tax benefit to largely offset; however, quarterly timing differences are expected throughout 2018. In the first quarter of 2018, the utility segment had a $4.3 million net timing benefit related to the lower federal tax rate, of which $1.6 million reversed in the second quarter of 2018. The remaining $2.7 million net benefit is expected to more than completely reverse in the third quarter of 2018 with an additional benefit in the fourth quarter of 2018 and little anticipated impact to annual results. See "Business Segments - Local Gas Distribution Utility Operations" below.

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HOLDING COMPANY

NW Natural is pursuing the 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, WUTC, and CPUC. We also received approval from our shareholders at our 2018 Annual Shareholders Meeting in May 2018. The Board and Management must take additional actions to implement the holding company structure, which we currently expect to happen on October 1, 2018 or at the beginning of 2019. To implement a holding company structure, NW Natural common stock would be converted into the same relative percentages of the holding company that each shareholder owns of NW Natural immediately prior to the reorganization. The structure 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" and Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Holding Company” in our 2017 Form 10-K.

DIVIDENDS

Dividend highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
Per common share	2018	2017	2018	2017	QTR Change	YTD Change
Dividends paid	$0.4725	$0.4700	$0.9450	$0.9400	$0.0025	$0.0050

In July 2018, the Board of Directors declared a quarterly dividend on our common stock of $0.4725 per share, payable on August 15, 2018, to shareholders of record on July 31, 2018, reflecting an annual indicated dividend rate of $1.89 per share.

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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 Completed General Rate Cases" below.

MIST GAS STORAGE. Our interstate storage activity at Mist is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates and terms of service. The OPUC also regulates the issuance of securities, system of accounts, and regulates 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.

In 2017, approximately 70% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 30% from California operations. In June 2018, we entered into a Purchase and Sale Agreement for the sale of all of our ownership interests in Gill Ranch, a natural gas storage facility located near Fresno, California, which is subject to approval by the CPUC and other customary closing conditions. See Note 15 for more information.

Most Recent Completed 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. In July 2018, the FERC issued an order finalizing its regulations regarding the effect of the TCJA. The new regulations will require NW Natural to file a petition for rate approval or a cost and revenue study to reflect the new federal corporate income tax rate within thirty days of the rate effective date of our Oregon rate case. This is approximately the same timeframe when a new cost and revenue study would be required under FERC's pre-existing requirements.

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.

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 and Optimization Sharing	X	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 June 30, 2018, we are also hedged in future gas years at approximately 41% for the 2018-19 gas year and between 2% and 18% 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 it was approved by the Commission in July 2018. As a result, we were not subject to a customer refund adjustment for 2017.

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.

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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 six months ended June 30, 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 June 30, 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. For additional information, see Note 15 in our 2017 Form 10-K.

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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.

We have concluded there was no earnings test adjustment for 2017 based on the environmental earnings test that was submitted in May 2018 and approved by the Commission in July 2018.

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 $5.5 million and $3.0 million during the six months ended June 30, 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.

In 2018, we received regulatory approval to refund an interstate storage credit of $11.7 million to our Oregon utility customers. Of this amount, $10.2 million was reflected in customers' June bills with the remainder to be credited to their bills in the third quarter. The 2017 interstate storage credit was approximately $11.7 million.

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. During the second quarter of 2018, we received approval from the CPUC.

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 amounts deferred prior to November 1, 2018. In addition, we updated our Oregon 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. In May 2018, we entered into agreements to acquire two privately-owned water utilities: Lehman Enterprises, Inc. and Sea View Water LLC both based on Whidbey Island near Seattle, Washington.

These transactions are subject to certain conditions, including approvals from the OPUC, the Idaho Public Utilities Commission (IPUC) and WUTC, respectively. We received regulatory approval in July 2018 from the IPUC to acquire Falls Water Company and expect this transaction to close in the third quarter of 2018. We have filed our application with the OPUC to acquire Salmon Valley Water Company and anticipate receiving approvals and closing this acquisition in 2018. In July 2018, we filed our application with the WUTC to acquire the Whidbey Island water companies and anticipate closing these transactions in 2019. We do not expect these transactions or their continuing operations to have a material financial impact.

OREGON GENERAL RATE CASE. In December 2017, we filed an Oregon general rate case requesting a $40.4 million or 6% revenue requirement increase, after an adjustment for the conservation 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 was $25.7 million, or approximately a 4% increase, after an adjustment for our conservation tariff deferral. The revised revenue requirement was 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. Also in March 2018, we made a supplemental filing to incorporate the interstate storage and asset management sharing open proceeding in the rate case docket to address matters raised in the cost study completed by a third-party.

In August 2018, NW Natural, OPUC Staff, Oregon Citizen's Utility Board, and the Alliance of Western Energy Customers, which comprise all of the parties to the rate case, filed with the OPUC a joint stipulation addressing all but three issues in the rate case (settlement). The settlement is subject to the review and approval of the OPUC. For new rates to go into effect, the OPUC must issue an order, which may approve or modify the terms of the settlement and address the remaining issues.

The settlement provides for a total of $16 million annual revenue requirement increase over our revenue from existing rates. This revenue requirement increase includes approximately $12 million that would otherwise by recovered under the conservation tariff deferral. The revenue requirement also reflects settlement of treatment of the impact of the

TCJA on the recoverable tax expense included in rates for the period after the date the new rates take effect, which is expected to be November 1, 2018. The revenue requirement is based upon the following agreements included in the settlement:

- capital structure of 50% debt and 50% equity;
- return on equity of 9.4%;
- cost of capital of 7.317%; and
- rate base of $1.192 billion, or an increase of $306 million since the last rate case.

The increase to revenue requirement is dependent upon our completion of certain capital projects prior to the rate effective date, and the amounts could be adjusted downward in the event that these projects are not completed. The three issues not addressed in this settlement and that the parties to the rate case expect to continue to litigate or continue to settle under a subsequent agreement are:

- the impact of the TCJA on our accumulated deferred income tax and tax expense during the period prior to the date the new rates take effect, which is expected to be November 1, 2018;
- matters relating to the future operation and timing of rate recovery of amounts reflected in the pension balancing account; and
- the sharing of revenues produced by optimization of certain assets and interstate storage operations.

The OPUC's order regarding the rate case is expected to be issued by the end of October 2018, with new 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

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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:

Dollars and therms in thousands, except EPS data	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	QTR Change	YTD Change
Utility net income (loss)	$(2,970)	$2,137	$36,913	$42,329	$(5,107)	$(5,416)
EPS - utility segment	$(0.10)	$0.07	$1.28	$1.47	$(0.17)	$(0.19)
Gas sold and delivered (in therms)	217,393	234,643	624,346	702,282	(17,250)	(77,936)
Utility margin(1)	$69,746	$74,479	$202,462	$216,640	$(4,733)	$(14,178)

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

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. The primary factors contributing to the $5.1 million, or $0.17 per share, decrease in utility net income were as follows:

- a $4.7 million decrease in utility margin due to:
  - a $2.8 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 $0.7 million increase from customer growth.
  - The majority of the remaining decrease was due to 38% warmer than average weather in 2018, compared to 14% colder than average weather in the prior period.
- a $2.5 million increase in operations and maintenance expense largely from payroll and benefits due to additional headcount and general salary increases; partially offset by
- a $2.8 million decrease in income tax expense largely due to changes in pre-tax income.

For the three months ended June 30, 2018, total utility volumes sold and delivered decreased 7% over the same period in 2017 due to 38% warmer than average weather in 2018 compared to 14% colder than average weather in 2017.

Overall, the TCJA reduced utility net income for the second quarter by $1.6 million as a result of the $2.1 million after-tax revenue deferral ($2.8 million pre-tax) more than offsetting the $0.5 million tax expense benefit.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. The primary factors contributing to the $5.4 million, or $0.19 per share, decrease in utility net income were as follows:

- a $14.2 million decrease in utility margin due to:
  - a $9.2 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 $2.3 million increase from customer growth.
  - The majority of the remaining decrease was due to 24% colder than average weather in the prior period.
- a $3.7 million increase in operations and maintenance expense largely from payroll and benefits due to additional headcount and general salary increases as well as higher professional service costs; and
-

- a $2.7 million increase in other expenses and income primarily related to higher depreciation and property taxes; partially offset by
- a $15.1 million decrease in income tax expense due to the decline of the U.S. federal corporate income tax rate to 21% in 2018 compared to 35% in the prior period and changes in pre-tax income.

For the six months ended June 30, 2018, total utility volumes sold and delivered decreased 11% over the same period in 2017 due to 11% warmer than average weather in 2018 compared to 24% colder than average weather in 2017.

Overall, the TCJA increased utility net income for the first six months of 2018 by $2.7 million as a result of a $9.5 million tax expense benefit more than offsetting the $6.8 million after-tax revenue deferral ($9.2 million pre-tax). We expect this benefit to more than completely reverse in the third quarter of 2018 with an additional benefit in the fourth quarter of 2018 and little anticipated impact to annual results.

We deferred $2.8 million and $9.2 million of revenue during the three and six months ended June 30, 2018, respectively, related to the estimated effects of the TCJA. We currently estimate the deferral for 2018 will be $8 to $12 million pre-tax. The deferral methodology, among other matters, is currently being determined through the open Oregon general rate case and the TCJA docket. See "Regulatory Matters - Tax Reform Deferral and Oregon General Rate Case" above. The revenue deferral is primarily 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. Additionally, during 2018, we expect the lower tax rate will increase the seasonality of

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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.

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

	Three Months Ended June 30,		Six Months Ended June 30,		Favorable/ (Unfavorable)	
In thousands, except degree day and customer data	2018	2017	2018	2017	QTR Change	YTD Change
Utility volumes (therms):						
Residential and commercial sales	103,637	113,869	381,656	441,392	(10,232)	(59,736)
Industrial sales and transportation	113,756	120,774	242,690	260,890	(7,018)	(18,200)
Total utility volumes sold and delivered	217,393	234,643	624,346	702,282	(17,250)	(77,936)
Utility operating revenues:						
Residential and commercial sales	$106,526	$117,296	$352,110	$397,573	$(10,770)	$(45,463)
Industrial sales and transportation	13,403	14,791	30,792	33,694	(1,388)	(2,902)
Other revenues	(1,414)	1,168	(6,454)	2,543	(2,582)	(8,997)
Less: Revenue taxes(1)	—	3,160	—	10,989	3,160	10,989
Total utility operating revenues	118,515	130,095	376,448	422,821	(11,580)	(46,373)
Less: Cost of gas	42,107	53,005	150,271	196,616	10,898	46,345
Less: Environmental remediation expense	1,882	2,611	6,506	9,565	729	3,059
Less: Revenue taxes(1)	4,780	—	17,209	—	(4,780)	(17,209)
Utility margin	$69,746	$74,479	$202,462	$216,640	$(4,733)	$(14,178)
Utility margin:(2)						
Residential and commercial sales	$64,036	$65,965	$192,490	$197,005	$(1,929)	$(4,515)
Industrial sales and transportation	7,038	7,565	15,342	16,257	(527)	(915)
Miscellaneous revenues	1,079	1,165	2,437	2,538	(86)	(101)
Gain (loss) from gas cost incentive sharing	128	(113)	1,008	838	241	170
Other margin adjustments(5)	(2,535)	(103)	(8,815)	2	(2,432)	(8,817)
Utility margin	$69,746	$74,479	$202,462	$216,640	$(4,733)	$(14,178)
Degree days(3)						
Average(4)	311	311	1,627	1,627	—	—
Actual	193	356	1,449	2,023	(46)%	(28)%
Percent colder (warmer) than average weather	(38)%	14%	(11)%	24%		

	As of June 30,			
Customers - end of period:	2018	2017	Change	Growth
Residential customers	673,479	662,376	11,103	1.7%
Commercial customers	68,160	67,580	580	0.9%
Industrial customers	1,028	1,012	16	1.6%
Total number of customers	742,667	730,968	11,699	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 include the $2.8 million and $9.2 million regulatory revenue deferral for the three and six months ended June 30, 2018, respectively, associated from the decline of the U.S. federal corporate income tax rate.

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Residential and Commercial Sales

Residential and commercial sales highlights include:

In thousands	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017	QTR Change	YTD Change
Volumes (therms):						
Residential sales	60,914	68,697	238,885	278,347	(7,783)	(39,462)
Commercial sales	42,723	45,172	142,771	163,045	(2,449)	(20,274)
Total volumes	103,637	113,869	381,656	441,392	(10,232)	(59,736)
Operating revenues:						
Residential sales	$69,644	$76,558	$236,231	$265,126	$(6,914)	$(28,895)
Commercial sales	36,882	40,738	115,879	132,447	(3,856)	(16,568)
Total operating revenues	$106,526	$117,296	$352,110	$397,573	$(10,770)	$(45,463)
Utility margin:						
Residential:						
Sales	$41,607	$45,043	$132,136	$150,370	$(3,436)	$(18,234)
Alternative Revenue:						
Weather normalization	1,142	(730)	2,985	(11,780)	1,872	14,765
Decoupling	1,259	921	(1,150)	(1,133)	338	(17)
Amortization of alternative revenue	268	—	1,051	—	268	1,051
Total residential utility margin	44,276	45,234	135,022	137,457	(958)	(2,435)
Commercial:						
Sales	18,766	18,125	57,063	58,231	641	(1,168)
Alternative Revenue:						
Weather normalization	411	(222)	1,004	(4,511)	633	5,515
Decoupling	2,123	2,829	4,717	5,828	(706)	(1,111)
Amortization of alternative revenue	(1,540)	—	(5,316)	—	(1,540)	(5,316)
Total commercial utility margin	19,760	20,732	57,468	59,548	(972)	(2,080)
Total utility margin	$64,036	$65,966	$192,490	$197,005	$(1,930)	$(4,515)

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. The primary factor contributing to the $1.9 million decrease in residential and commercial utility margin is a decline in usage from warmer than 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.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. The primary factor contributing to the $4.5 million decrease in residential and commercial utility margin is a decline in usage from 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.

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Industrial Sales and Transportation

Industrial sales and transportation highlights include:

In thousands	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017	QTR Change	YTD Change
Volumes (therms):						
Industrial - firm sales	7,858	7,637	17,866	18,013	221	(147)
Industrial - firm transportation	38,368	38,897	83,744	87,626	(529)	(3,882)
Industrial - interruptible sales	12,375	13,204	27,980	30,181	(829)	(2,201)
Industrial - interruptible transportation	55,155	61,036	113,100	125,070	(5,881)	(11,970)
Total volumes	113,756	120,774	242,690	260,890	(7,018)	(18,200)
Utility margin:						
Industrial - firm and interruptible sales	$2,468	$2,775	$5,705	$6,115	$(307)	$(410)
Industrial - firm and interruptible transportation	4,570	4,790	9,637	10,142	(220)	(505)
Industrial - sales and transportation	$7,038	$7,565	$15,342	$16,257	$(527)	$(915)

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Sales and transportation volumes decreased by 7.0 million therms, or 6%, and industrial utility margin decreased slightly by $0.5 million due to lower usage from warmer than average weather in 2018 compared to colder than average weather in 2017.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Sales and transportation volumes decreased by 18.2 million therms, or 7%, and industrial utility margin decreased by $0.9 million due to lower usage from colder than average weather in 2017.

Cost of Gas

Cost of gas highlights include:

Dollars and therms in thousands	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017	QTR Change	YTD Change
Cost of gas	$42,107	$53,005	$150,271	$196,616	$(10,898)	$(46,345)
Volumes sold (therms)[1]	123,870	134,710	427,502	489,586	(10,840)	(62,084)
Average cost of gas (cents per therm)	$0.34	$0.39	$0.35	$0.40	$(0.05)	$(0.05)
Gain (loss) from gas cost incentive sharing[2]	$128	$(113)	$1,008	$838	$241	$170

(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 JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Cost of gas decreased $10.9 million, or 21%, primarily due to a 8% decrease in volumes sold reflecting warmer than average weather in 2018 compared to colder than average weather in the prior period and a 13% decrease in average cost of gas due to lower natural gas prices, slightly offset by customer growth.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Cost of gas decreased $46.3 million, or 24%, primarily due to a 13% decrease in volumes sold reflecting colder than average weather in the prior period, and a 13% decrease in average cost of gas due to lower natural gas prices, offset by customer growth.

Other
During the second quarter of 2018, we reevaluated our reportable segments and concluded that the remaining gas storage activities no longer meet the requirements to be reported as a segment. Our ongoing non-utility gas storage activity at Mist is now reported as other, and all prior periods presented reflect this change and the removal of our discontinued operation, Gill Ranch Storage.

Other primarily consists of our non-utility gas storage operations at Mist; asset management services using our utility and non-utility storage and transportation capacity; our 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 and potential holding company activities; and other non-utility investments and business development activities.

Other highlights include:

In thousands, except EPS data	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	QTR Change	YTD Change
Other net income	$2,631	$1,938	$4,759	$3,143	$ 693	$ 1,616
EPS - other	$0.09	$0.07	$0.17	$0.11	$ 0.02	$ 0.06

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Other net income was $2.6 million, or $0.09 per share, compared to net income of $1.9 million, or $0.07 per share, in the prior period. Net income increased $0.7 million primarily due to increased income from our non-utility gas storage operations at Mist, slightly offset by an increase in costs associated with business development activities, including costs associated with regulated water and the holding company formation activities.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Other net income was $4.8 million, or $0.17 per share, compared to net income of $3.1 million, or $0.11 per share, in the prior period. Net income increased $1.6 million primarily due to increased income from our non-utility gas storage operations at Mist, slightly offset by an increase in costs associated with business development activities, including costs associated with regulated water and the holding company formation 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:

In thousands	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	QTR Change	YTD Change
Operations and maintenance	$38,028	$34,997	$77,551	$72,443	$ 3,031	$ 5,108

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Operations and maintenance expense increased $3.0 million reflecting higher utility payroll and benefits due to additional headcount and general salary increases.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Operations and maintenance expense increased $5.1 million reflecting higher utility payroll and benefits due to additional headcount and general salary increases, as well as higher professional services.

Depreciation and Amortization

Depreciation and amortization highlights include:

In thousands	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	QTR Change	YTD Change
Depreciation and amortization	$21,147	$20,224	$42,022	$40,177	$ 923	$ 1,845

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Depreciation and amortization expense increased $0.9 million due to utility plant additions that included investments in our natural gas transmission and distribution system, facility upgrades, and enhanced technology.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Depreciation and amortization expense increased $1.8 million due to utility plant additions that included investments in our natural gas transmission and distribution system, facility upgrades, and enhanced technology.

Other Income (Expense), Net

Other income (expense), net highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
In thousands	2018	2017	2018	2017	QTR Change	YTD Change
Other income (expense), net	$7	$(340)	$(827)	$(763)	$ 347	$ (64)

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Other income (expense), net increased $0.3 million primarily due to a $0.5 million increase in the equity portion of AFUDC, partially offset by a $0.2 million decrease in regulatory interest income, net reflecting higher regulatory liability balances.

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SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Other income (expense), net decreased $0.1 million primarily due to a $0.7 million increase in other net expense activity and a $0.3 million decrease in regulatory interest income, net, largely offset by a $1.0 million increase in the equity portion of AFUDC.

Interest Expense, Net

Interest expense, net highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
In thousands	2018	2017	2018	2017	QTR Change	YTD Change
Interest expense, net	$8,771	$9,473	$18,045	$19,103	$(702)	$(1,058)

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Interest expense, net decreased $0.7 million due to a $0.7 million increase in the debt portion of AFUDC.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Interest expense, net decreased $1.1 million primarily due to a $1.3 million increase in the debt portion of AFUDC, partially offset by a $0.3 million increase in interest expense from higher long-term debt balances as of June 30, 2018 compared to the prior period.

Income Tax Expense

Income tax expense highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,			
In thousands	2018	2017	2018	2017	QTR Change	YTD Change
Income tax expense (benefit)	$(156)	$2,547	$15,476	$30,178	$(2,703)	$(14,702)

THREE MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Income tax expense decreased $2.7 million due to changes in pre-tax income and the benefit from the decline of the U.S. federal corporate income tax rate to 21% in 2018 from 35% in the prior period.

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. Income tax expense decreased $14.7 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 changes in pre-tax income.

Pending sale of Gill Ranch Storage

On June 20, 2018, NWN Gas Storage, our wholly owned subsidiary, entered into a Purchase and Sale Agreement (the Agreement) that provides for the sale by NWN Gas Storage of all of the membership interests in Gill Ranch. Gill Ranch owns a 75% interest in the natural gas storage facility located near Fresno, California known as the Gill Ranch Gas Storage Facility. Pacific Gas and Electric Company (PG&E) owns the remaining 25% interest in the Gill Ranch Gas Storage Facility. We expect the transaction to close within 12 months of signing and in 2019. The closing of the transaction is subject to approval by the CPUC and other customary closing conditions.

The results of Gill Ranch Storage have been determined to be discontinued operations and are presented separately, net of tax, from the results of continuing operations for all periods presented. See Note 15 for more information on the

Agreement and the results of our discontinued operations.

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. The CPUC also regulates the issuance of securities, system of accounts, and regulates intrastate storage services. The California Department of Oil Gas and Geothermal Resources (DOGGR) regulations for gas storage wells were finalized in June 2018, and the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) proposed new federal regulations for underground natural gas storage facilities, which are expected to be finalized during 2019 and increase costs for all storage providers. We will continue to monitor and assess the new regulations until the sale is complete, which is expected in 2019.

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

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

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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.

Our consolidated capital structure was as follows:

	June 30,		December 31,
	2018	2017	2017
Common stock equity	48.5 %	54.6 %	47.1 %
Long-term debt	43.7	41.5	43.3
Short-term debt, including current maturities of long-term debt	7.8	3.9	9.6
Total	100.0 %	100.0 %	100.0 %

Liquidity and Capital Resources
At June 30, 2018 we had $8.8 million of cash and cash equivalents compared to $20.9 million at June 30, 2017 due to lower cash collections from customers as a result of warmer weather in the first half of 2018 as compared to the first half 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.

In the event our senior unsecured long-term debt ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit, or other forms of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings while we were in a net loss position. We were not required to post collateral at June 30, 2018. However, if the credit risk-related contingent features underlying these contracts were triggered on June 30, 2018, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $7.0 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.

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 June 30, 2018, our utility had $47.1 million short-term debt outstanding due to the sale of commercial paper, compared to none outstanding at June 30, 2017. The weighted average interest rate on short-term debt outstanding at June 30, 2018 was 2.3%.

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 June 30, 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 June 30, 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 June 30, 2018 and 2017, with consolidated indebtedness to total capitalization ratios of 51.5% and 45.4%, 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 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.

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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 six months ended June 30, 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:

	Six Months Ended June 30,		
In thousands	2018	2017	YTD Change
Cash provided by operating activities	$162,652	$194,231	$(31,579)

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. The significant factors contributing to the $31.6 million decrease in cash flows provided by operating activities were as follows:

- a net decrease of $2.4 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 $10.5 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
- an increase of $4.3 million of cash outflow due to $13.3 million of income taxes paid in 2018 compared to $9.1 million in the prior period;

During the six months ended June 30, 2018, we contributed $5.6 million to our utility's qualified defined benefit pension plan, compared to $7.3 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:

In thousands	Six Months Ended June 30, 2018	2017	YTD Change
Total cash used in investing activities	$(102,458)	$(94,722)	$(7,736)
Capital expenditures supporting continuing operations	(102,370)	(94,333)	(8,037)

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. The $7.7 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. The estimated capital expenditures in this range include, but are not limited to, the following items:

- $650 to $700 million of core utility capital expenditures that will support continued customer growth, distribution system maintenance and improvements, technology investments, and utility gas storage facility maintenance;
- $60 to $70 million related to planned upgrades and refurbishments to utility storage facilities and resource centers; and
- $20 to $30 million of additional investments to complete the North Mist gas storage facility expansion in 2018.

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.

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Our 2018 utility capital expenditures are estimated to be between $190 and $220 million. This range includes $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:

	Six Months Ended June 30,		
In thousands	2018	2017	YTD Change
Total cash used in financing activities	$(54,911)	$(82,176)	$27,265
Change in short-term debt	(7,100)	(53,300)	46,200
Change in long-term debt	(22,000)	—	(22,000)

SIX MONTHS ENDED JUNE 30, 2018 COMPARED TO JUNE 30, 2017. The $27.3 million decrease in cash used in financing activities was primarily due to lower repayments of $46.2 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 six months ended June 30, 2018 and twelve months ended June 30, 2018 and December 31, 2017 our ratios of earnings to fixed charges were 3.38, 2.95 and 3.44, respectively. For purposes of this calculation, earnings consist of net income from continuing operations 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 June 30, 2018, our total estimated liability related to environmental sites is $120.1 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 incorporated in Note 5 and Note 15 relating to revenue and discontinued operations, respectively. 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 six months ended June 30, 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 June 30, 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).

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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 June 30, 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
04/01/18-04-30/18	—	$ —	—	—
05/01/18-05/31/18	7,342	59.76	—	—
06/01/18-06/30/18	—	—	—	—
Total	7,342	59.76	2,124,528	$ 16,732,648

(1) During the quarter ended June 30, 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, 7,342 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended June 30, 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 June 30, 2018, no shares of our common stock were repurchased pursuant to our Board-Approved share repurchase program. In May 2018, we received Board Approval to extend the repurchase program through May 2019. 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.

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Quarterly Report on Form 10-Q
For the Quarter Ended June 30, 2018

Exhibit Index

Exhibit Number	Document
10	Purchase and Sale Agreement dated June 20, 2018, between NW Natural Gas Storage LLC and SENSA Holdings LLC.
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.	The following materials from Northwest Natural Gas Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 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.

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SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)
Dated: August 7, 2018

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

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