

Otter Tail Corp
Form 10-Q
May 09, 2018

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE
ACT OF 1934**

For the quarterly period ended March 31, 2018

OR

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE
ACT OF 1934**

For the transition period from to

Commission file number 0-53713

OTTER TAIL CORPORATION
(Exact name of registrant as specified in its charter)

Minnesota 27-0383995
(State or other jurisdiction of (I.R.S. Employer
incorporation or organization) Identification No.)

215 South Cascade Street, Box 496, Fergus Falls, Minnesota 56538-0496
(Address of principal executive offices) (Zip Code)

866-410-8780
(Registrant's telephone number, including area code)

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(Former name, former address and former fiscal year, if changed since last report)

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 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 No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth 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 Accelerated filer

Non-accelerated filer Smaller reporting company Emerging growth company
(Do not check if a smaller reporting company)

If an emerging growth company, indicate by checkmark 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 by Rule 12b-2 of the Exchange Act).

Yes No

Indicate the number of shares outstanding of each of the issuer's classes of Common Stock, as of the latest practicable date:

April 30, 2018 – 39,651,236 Common Shares (\$5 par value)

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OTTER TAIL CORPORATION

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FINANCIAL
INFORMATION**Item 1. financial**
statements**Otter Tail**
Corporation
Consolidated
Balance Sheets
(not audited)

<i>(in thousands)</i>	March 31,	December
	2018	31,
		2017
Assets		
Current Assets		
Cash and Cash Equivalents	\$1,121	\$16,216
Accounts Receivable:		
Trade—Net	94,265	68,466
Other	7,109	7,761
Inventories	87,999	88,034
Unbilled Receivables	18,692	22,427
Income Taxes Receivable	--	1,181
Regulatory Assets	19,736	22,551
Other	11,210	12,491
Total Current Assets	240,132	239,127
Investments	8,648	8,629
Other Assets	35,763	36,006
Goodwill	37,572	37,572
Other Intangibles—Net	13,420	13,765
Regulatory Assets	125,667	129,576
Plant		
Electric Plant in Service	1,986,385	1,981,018
Nonelectric Operations	219,942	216,937
Construction Work in Progress	153,963	141,067
Total Gross Plant	2,360,290	2,339,022
Less Accumulated Depreciation and Amortization	814,074	799,419

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Net Plant	1,546,216	1,539,603
Total Assets	\$2,007,418	\$2,004,278

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail
Corporation
Consolidated
Balance
Sheets**
(not audited)

<i>(in thousands, except share data)</i>	March 31, 2018	December 31, 2017
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	\$30,319	\$112,371
Current Maturities of Long-Term Debt	171	186
Accounts Payable	87,179	84,185
Accrued Salaries and Wages	14,806	21,534
Accrued Federal and State Income Taxes	984	--
Accrued Taxes	17,585	16,808
Regulatory Liabilities	5,119	9,688
Other Accrued Liabilities	9,940	11,389
Liabilities of Discontinued Operations	--	492
Total Current Liabilities	166,103	256,653
Pensions Benefit Liability	89,552	109,708
Other Postretirement Benefits Liability	70,040	69,774
Other Noncurrent Liabilities	23,482	22,769
Commitments and Contingencies (note 8)		
Deferred Credits		
Deferred Income Taxes	103,009	100,501
Deferred Tax Credits	21,025	21,379
Regulatory Liabilities	233,279	232,893
Other	2,935	3,329
Total Deferred Credits	360,248	358,102
Capitalization		
Long-Term Debt—Net	589,943	490,380
Cumulative Preferred Shares – Authorized 1,500,000 Shares Without Par Value; Outstanding – None	--	--
Cumulative Preference Shares – Authorized 1,000,000 Shares Without Par Value; Outstanding – None	--	--

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Common Shares, Par Value \$5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2018—39,626,594 Shares; 2017—39,557,491 Shares	198,133	197,787
Premium on Common Shares	341,841	343,450
Retained Earnings	174,209	161,286
Accumulated Other Comprehensive Loss	(6,133)	(5,631)
Total Common Equity	708,050	696,892
Total Capitalization	1,297,993	1,187,272
Total Liabilities and Equity	\$2,007,418	\$2,004,278

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail
Corporation
Consolidated
Statements
of Income**
(not audited)

	Three Months Ended	
	March 31,	
	2018	2017
<i>(in thousands, except share and per-share amounts)</i>		
Operating Revenues		
Electric:		
Revenues from Contracts with Customers	\$ 123,825	\$ 119,782
Changes in Accrued Revenues under Alternative Revenue Programs	(875) (1,239)
Total Electric Revenues	122,950	118,543
Product Sales under Contracts with Customers	118,316	95,574
Total Operating Revenues	241,266	214,117
Operating Expenses		
Production Fuel – Electric	18,706	16,382
Purchased Power - Electric	21,593	19,188
Electric Operation and Maintenance Expenses	39,475	37,277
Cost of Products Sold (depreciation included below)	88,785	75,277
Other Nonelectric Expenses	12,494	10,135
Depreciation and Amortization	18,763	17,854
Property Taxes – Electric	3,835	3,798
Total Operating Expenses	203,651	179,911
Operating Income	37,615	34,206
Interest Charges	7,372	7,462
Nonservice Cost Components of Postretirement Benefits	1,417	1,405
Other Income	1,183	553
Income Before Income Taxes – Continuing Operations	30,009	25,892
Income Tax Expense – Continuing Operations	3,794	6,363
Net Income from Continuing Operations	26,215	19,529
Income from Discontinued Operations – net of Income Tax Expense of \$38 in 2017	--	56
Net Income	\$26,215	\$19,585
Average Number of Common Shares Outstanding—Basic	39,550,874	39,350,802
Average Number of Common Shares Outstanding—Diluted	39,863,682	39,640,725
Basic Earnings Per Common Share:		
Continuing Operations	\$0.66	\$0.50

Discontinued Operations	--	--
	\$0.66	\$0.50
Diluted Earnings Per Common Share:		
Continuing Operations	\$0.66	\$0.49
Discontinued Operations	--	--
	\$0.66	\$0.49
Dividends Declared Per Common Share	\$0.335	\$0.320

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail
Corporation
Consolidated
Statements of
Comprehensive
Income**
(not audited)

	Three Months Ended	
	March 31,	
	2018	2017
<i>(in thousands)</i>		
Net Income	\$26,215	\$19,585
Other Comprehensive (Loss) Income:		
Unrealized Gains on Available-for-Sale Securities:		
Reversal of Previously Recognized Gains on Available for Sale Securities Included in Other Income During Period	(110)	--
Unrealized (Losses) Gains Arising During Period	(66)	17
Income Tax Benefit (Expense)	37	(6)
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(139)	11
Pension and Postretirement Benefit Plans:		
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 10)	227	157
Income Tax Expense	(59)	(63)
Adjustment to Income Tax Expense Related to 2017 Tax Cuts and Jobs Act	(531)	--
Pension and Postretirement Benefit Plans – net-of-tax	(363)	94
Total Other Comprehensive (Loss) Income	(502)	105
Total Comprehensive Income	\$25,713	\$19,690

See accompanying condensed notes to consolidated financial statements.

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**Otter Tail
Corporation
Consolidated
Statements
of Cash
Flows**
(not audited)

	Three Months Ended	
	March 31,	
	2018	2017
<i>(in thousands)</i>		
Cash Flows from Operating Activities		
Net Income	\$26,215	\$19,585
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Net Income from Discontinued Operations	--	(56)
Depreciation and Amortization	18,763	17,854
Deferred Tax Credits	(354)	(366)
Deferred Income Taxes	2,901	4,512
Change in Deferred Debits and Other Assets	6,295	5,005
Discretionary Contribution to Pension Plan	(20,000)	--
Change in Noncurrent Liabilities and Deferred Credits	(5,091)	1,314
Allowance for Equity/Other Funds Used During Construction	(638)	(170)
Stock Compensation Expense—Equity Awards	1,146	1,150
Other—Net	(284)	(5)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(25,047)	(15,521)
Change in Inventories	35	2,267
Change in Other Current Assets	2,334	(22)
Change in Payables and Other Current Liabilities	(2,598)	(13,986)
Change in Interest and Income Taxes Receivable/Payable	1,163	(321)
Net Cash Provided by Continuing Operations	4,840	21,240
Net Cash Used in Discontinued Operations	(200)	(39)
Net Cash Provided by Operating Activities	4,640	21,201
Cash Flows from Investing Activities		
Capital Expenditures	(23,618)	(30,113)
Net Proceeds from Disposal of Noncurrent Assets	510	612
Cash Used for Investments and Other Assets	(719)	(508)
Net Cash Used in Investing Activities	(23,827)	(30,009)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	2,338	7,999
Net Short-Term (Repayments) Borrowings	(82,052)	16,293
Proceeds from Issuance of Common Stock – net of Issuance Expenses	--	1,958
Payments for Retirement of Capital Stock	(2,409)	(1,759)
Proceeds from Issuance of Long-Term Debt	100,000	--

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Short-Term and Long-Term Debt Issuance Expenses	(433)	--
Payments for Retirement of Long-Term Debt	(60)	(3,057)
Dividends Paid	(13,292)	(12,626)
Net Cash Provided by Financing Activities	4,092	8,808
Net Change in Cash and Cash Equivalents	(15,095)	--
Cash and Cash Equivalents at Beginning of Period	16,216	--
Cash and Cash Equivalents at End of Period	\$1,121	\$--

See accompanying condensed notes to consolidated financial statements.

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OTTER TAIL CORPORATION

CONDENSED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(not audited)

In the opinion of management, Otter Tail Corporation (the Company) has included all adjustments (including normal recurring accruals) necessary for a fair presentation of the consolidated financial statements for the periods presented. The consolidated financial statements and condensed notes thereto should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017. Because of seasonal and other factors, the earnings for the three months ended March 31, 2018 should not be taken as an indication of earnings for all or any part of the balance of the year.

The following condensed notes are numbered to correspond to numbers of the notes included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

1. Summary of Significant Accounting Policies

Revenue Recognition

In *May 2014* the Financial Accounting Standards Board (FASB) issued a major update to the Accounting Standards Codification (ASC), Accounting Standards Update (ASU) *No. 2014-09, Revenue from Contracts with Customers (Topic 606)* (ASC 606). The Company adopted the updates in ASC 606 effective *January 1, 2018* on a modified retrospective basis but did *not* record a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASC 606 had *no* material impact on the timing of revenue recognition for the Company or its subsidiaries. ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Due to the diverse business operations of the Company, recognition of revenue from contracts with customers depends on the product produced and sold or service performed. The Company recognizes revenue from contracts with customers, at prices that are fixed or determinable as evidenced by an agreement with the customer, when the Company has met its performance obligation under the contract and it is probable that the Company will collect the

amount to which it is entitled in exchange for the goods or services transferred or to be transferred to the customer. Depending on the product produced and sold or service performed and the terms of the agreement with the customer, the Company recognizes revenue either over time, in the case of delivery or transmission of electricity or related services or the production and storage of certain custom-made products, or at a point in time for the delivery of standardized products and other products made to the customers specifications where the terms of the contract require transfer of the completed product. Based on review of the Company's revenue streams, the Company has *not* identified any contracts where the timing of revenue recognition will change as a result of the adoption of the updates in ASC 606. Provisions for sales returns, early payment terms discounts, volume-based variable pricing incentives and warranty costs are recorded as reductions to revenue at the time revenue is recognized based on customer history, historical information and current trends.

In addition to recognizing revenue from contracts with customers under ASC 606, the Company also records adjustments to Electric segment revenues for amounts subject to future collection or refund under alternative revenue programs (ARPs) as defined in ASC Topic 980, *Regulated Operations* (ASC 980). The ARP revenue adjustments are recorded on the basis of recoverable costs incurred and returns earned under rate riders on a separate line on the face of the Company's consolidated statements of income as they do *not* meet the criteria to be classified as revenue from contracts with customers.

Electric Segment Revenues—In the Electric segment, the Company recognizes revenue in *two* categories: (1) revenues from contracts with customers and (2) adjustments to revenues for amounts collectible or refundable under ARPs.

Most Electric segment revenues are earned from the generation, transmission and sale of electricity to retail customers at rates approved by regulatory commissions in the states where Otter Tail Power Company (OTP) provides service. OTP also earns revenue from the transmission of electricity for others over the transmission assets it owns separately or jointly with other transmission service providers under rate tariffs established by the independent transmission system operator and approved by the Federal Energy Regulatory Commission (FERC). A *third* source of revenue for OTP comes from the generation and sale of electricity to wholesale customers at contract or market rates. Revenues from all these sources meet the criteria to be classified as revenue from contracts with customers and are recognized over time as energy is delivered or transmitted. Revenue is recognized based on the metered quantity of electricity delivered or transmitted at the applicable rates. For electricity delivered and consumed after a meter is read but prior to the end of the reporting period, OTP records revenue and an unbilled receivable based on estimates of the kilowatt-hours (kwh) of energy delivered to the customer.

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ARPs provide for adjustments to rates outside of a general rate case proceeding, usually as a surcharge applied to future billings typically through the use of rate riders subject to periodic adjustments, to encourage or incentivize investments in certain areas such as conservation, renewable energy, pollution reduction or control, improved infrastructure of the transmission grid or other programs that provide benefits to the general public under public policy, laws or regulations. ARP riders generally provide for the recovery of specified costs and investments and include an incentive component to provide the regulated utility with a return on amounts invested. OTP currently is recovering costs and earning incentives or returns on investments subject to recovery under several ARP rate riders, including:

In Minnesota: Transmission Cost Recovery (TCR), Environmental Cost Recovery (ECR), Renewable Resource Adjustment (RRA) and Conservation Improvement Program (CIP) riders.

In North Dakota: TCR, ECR and RRA riders

In South Dakota: TCR, ECR and Energy Efficiency Plan (conservation) riders.

OTP accrues ARP revenue on the basis of costs incurred, investments made and returns on those investments that qualify for recovery through established riders. Amounts billed under riders in effect at the time of the billing are included in revenues from contracts with customers. Amounts accrued and subject to future recovery, or amounts billed that are subject to refund, through future rider rate updates and adjustments are reported as ARP revenue adjustments on a separate line in the revenue section of the Company's consolidated statement of income. See table in note 3 for total revenues billed and accrued under ARP riders for the *three*-month periods ended *March 31, 2018* and *2017*.

Manufacturing Segment Revenues—Companies in the Manufacturing segment, BTD Manufacturing, Inc. (BTD) and T.O. Plastics, Inc. (T.O. Plastics), earn revenue predominantly from the production and delivery of custom-made or standardized parts to customers across several industries. BTD also earns revenue from the production and sale of tools and dies to other manufacturers. For the production and delivery of standardized products and other products made to the customers specifications where the terms of the contract require transfer of the completed product, the operating company has met its performance obligation and recognizes revenue at the point in time when the product is shipped and adjusts the revenue for volume rebate variable pricing considerations the company expects the customer will earn and applicable early payment discounts the company expects the customer will take. For revenue recognized on products when shipped, the operating companies have *no* further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Plastics Segment Revenues—Companies in our Plastics segment earn revenue predominantly from the sale and delivery of standardized polyvinyl-chloride (PVC) pipe products produced at their manufacturing facilities. Revenue from the sale of these products is recognized at the point in time when the product is shipped based on prices agreed to in a purchase order. Billed amounts of revenue recognized are adjusted for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. For revenue recognized on shipped products, there is *no* further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point. The Plastics segment has *one* customer for which it produces and stores a product made to the customer's specifications and design under a build

and hold agreement. For sales to this customer, the operating company recognizes revenue as the custom-made product is produced, adjusting the amount of revenue for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. Ownership of the pipe transfers to the customer prior to delivery and the operating company is paid a negotiated fee for storage of the pipe. Revenue for storage of the pipe is also recognized over time as the pipe is stored.

See operating revenue table in note 2 to consolidated financial statements for a disaggregation of the Company's revenues by business segment for the *three*-month periods ended *March 31, 2018* and *2017*.

Agreements Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases and carried at historical cost in the accompanying balance sheet. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. The Company does *not* offset assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet.

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The Company follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The *three* levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or *no* observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and *may* include complex and subjective models and forecasts.

The following tables present, for each of the hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of *March 31, 2018* and *December 31, 2017*:

March 31, 2018 (<i>in thousands</i>)	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	\$1,220		
Corporate Debt Securities – Held by Captive Insurance Company		\$5,341	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company			1,779
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan		870	
Total Assets	\$2,090	\$7,120	

December 31, 2017 <i>(in thousands)</i>	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	\$1,285		
Corporate Debt Securities – Held by Captive Insurance Company		\$5,373	
Government-Backed and Government-Sponsored Enterprises’ Debt Securities – Held by Captive Insurance Company			1,787
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	823		
Total Assets	\$2,108	\$7,160	

The valuation techniques and inputs used for the Level 2 fair value measurements in the table above are as follows:

Government-Backed and Government-Sponsored Enterprises’ and Corporate Debt Securities Held by the Company’s Captive Insurance Company – Fair values are determined on the basis of valuations provided by a *third*-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service *may* be based on broker quotes.

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Coyote Station Lignite Supply Agreement – Variable Interest Entity—In *October 2012* the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in *May 2016* and ending in *December 2040*. The price per ton paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from *May 2016* through *December 2040* and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. *No* single owner of Coyote Station owns a majority interest in Coyote Station and *none*, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, *none* of the owners individually, including OTP, is considered a primary beneficiary of the VIE and the Company is *not* required to include CCMC in its consolidated financial statements.

If the LSA terminates prior to the expiration of its term or the production period terminates prior to *December 31, 2040* and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of *March 31, 2018* could be as high as \$56.5 million, OTP's 35% share of unrecovered costs.

Inventories

Inventories, valued at the lower of cost or net realizable value, consist of the following:

	March	December
	31,	31,
(in thousands)	2018	2017
Finished Goods	\$25,341	\$ 26,605
Work in Process	17,224	14,222
Raw Material, Fuel and Supplies	45,434	47,207
Total Inventories	\$87,999	\$ 88,034

Goodwill and Other Intangible Assets

An assessment of the carrying amounts of goodwill of the Company's operating units as of *December 31, 2017* indicated the fair values are substantially in excess of their respective book values and *not* impaired.

The following table indicates there were *no* changes to goodwill by business segment during the *first three* months of *2018*:

	Gross Balance	Accumulated Impairments	Balance (net of impairments) December 31, 2017	Adjustments to Goodwill in 2018	Balance (net of impairments) March 31, 2018
<i>(in thousands)</i>	December 31, 2017				
Manufacturing	\$ 18,270	\$ --	\$ 18,270	\$ --	\$ 18,270
Plastics	19,302	--	19,302	--	19,302
Total	\$ 37,572	\$ --	\$ 37,572	\$ --	\$ 37,572

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Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC Topic 360-10-35, *Property, Plant, and Equipment—Overall—Subsequent Measurement*.

The following table summarizes the components of the Company's intangible assets at *March 31, 2018* and *December 31, 2017*:

	Gross Carrying	Accumulated Amortization	Net Carrying	Remaining Amortization
	Amount	Amount	Amount	Periods (months)
March 31, 2018 (in thousands)				
Amortizable Intangible Assets:				
Customer Relationships	\$ 22,491	\$ 9,277	\$ 13,214	21 - 209
Covenant not to Compete	590	508	82	5
Other	154	30	124	29
Total	\$ 23,235	\$ 9,815	\$ 13,420	
December 31, 2017 (in thousands)				
Amortizable Intangible Assets:				
Customer Relationships	\$ 22,491	\$ 8,994	\$ 13,497	24 - 212
Covenant not to Compete	590	459	131	8
Other	154	17	137	32
Total	\$ 23,235	\$ 9,470	\$ 13,765	

The amortization expense for these intangible assets was:

	Three	
	Months	
	Ended	
	March 31,	
(in thousands)	2018	2017
Amortization Expense – Intangible Assets	\$345	\$332

The estimated annual amortization expense for these intangible assets for the next *five* years is:

<i>(in thousands)</i>	2018	2019	2020	2021	2022
Estimated Amortization Expense – Intangible Assets	\$1,315	\$1,184	\$1,133	\$1,099	\$1,099

Supplemental Disclosures of Cash Flow Information

<i>(in thousands)</i>	As of March 31,	
	2018	2017
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	\$10,451	\$10,811

New Accounting Standards Adopted

ASU 2014-09—In May 2014 the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. The Company adopted the updates in ASC 606 effective *January 1, 2018* on a modified retrospective basis. See disclosures above under Revenue Recognition.

ASU 2016-01—In January 2016 the FASB issued ASU No. 2016-01, *Financial Instruments—Overall (Subtopic 825-10) (ASU 2016-01)*. The amendments in ASU 2016-01 address certain aspects of recognition, measurement, presentation, and disclosure of financial instruments and require equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. For the Company, the amendments in ASU 2016-01 are effective for fiscal years beginning after *December 15, 2017*, including interim periods within those fiscal years. The Company adopted the updates in ASU 2016-01 in the *first* quarter of 2018, which resulted in changes in the fair value of equity instruments held as investments by the Company’s captive insurance company being classified in net income. The fair value of equity instruments held by the Company’s captive insurance company on *March 31, 2018* were \$1,220,000 and the amount of unrealized gains on those investments recorded in net income in the *first* quarter of 2018 was \$87,000.

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ASU 2017-07—In March 2017 the FASB issued ASU No. 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (ASU 2017-07)*, with the intent of improving the presentation of net periodic pension cost and net periodic postretirement benefit cost. ASC Topic 715, *Compensation—Retirement Benefits (ASC 715)*, does *not* prescribe where the amount of net benefit cost should be presented in an employer’s income statement and does *not* require entities to disclose by line item the amount of net benefit cost that is included in the income statement or capitalized in assets. The amendments in ASU 2017-07 require that an employer report the service cost component of periodic benefit costs in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period, which the Company has provided in the electric operation and maintenance and other nonelectric expense lines on its income statement. The other components of net benefit cost as defined in ASC 715 are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The Company has provided the amount of the non-service cost components of net periodic postretirement benefit costs in a separate line below interest expense on the face of its consolidated income statement. The amendments in ASU 2017-07 also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of internally manufactured inventory or a self-constructed asset). The amendments in ASU 2017-07 are effective for annual periods beginning after *December 15, 2017*, including interim periods within those annual periods. The amendments have been applied retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the Company’s consolidated income statements and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit cost in assets.

The majority of the Company’s benefit costs to which the amendments in ASU 2017-07 apply are related to benefit plans in place at OTP, the Company’s regulated provider of electric utility services. The amendments in ASU 2017-07 deviate significantly from current prescribed ratemaking and regulatory accounting treatment of postretirement benefit costs applicable to OTP, which require the capitalization of a portion of all the components of net periodic benefit costs be included in rate base additions and provide for rate recovery of the non-capitalized portion of all the components of net periodic pension costs as recoverable operating expenses. The Company has assessed the impact adoption of the amendments in ASU 2017-07 will have on its consolidated financial statements, financial position and results of operations and OTP has established regulatory assets to reflect the effect of the required regulatory accounting treatment of the non-service cost components that cannot be capitalized to plant in service under ASU 2017-07.

The Company’s non-service cost components of net periodic post-retirement benefit costs that were capitalized to plant in service in 2017 that would have been recorded as regulatory assets if the amendments in ASU 2017-07 were applicable in 2017 were \$0.8 million. The Company’s non-service costs components of net periodic postretirement benefit costs included in operating expense in 2017 and 2016 that will be reported in other income and deductions in the Company’s 2018 annual report on Form 10-K after adoption of ASU 2017-07 were \$5.6 million for 2017 and \$5.1 million for 2016. Additional information on the allocation of postretirement benefit costs for the *three-month* periods ended *March 31, 2018* and 2017 is provided in note 10 to these consolidated financial statements for the Company’s major benefit programs presented.

New Accounting Standards Pending Adoption

ASU 2016-02—In *February 2016* the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after *December 15, 2018*, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. The Company has developed a list of all current leases outstanding and continues to review ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and is evaluating transition options. The Company does *not* currently plan to apply the amendments in ASU 2016-02 to its consolidated financial statements prior to 2019.

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ASU 2017-04—In January 2017 the FASB issued ASU No. 2017-04, *Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04), which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit’s goodwill with the carrying amount of that goodwill. In computing the implied fair value of goodwill under Step 2, an entity must perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under the amendments in ASU 2017-04, an entity will perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity will recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit’s fair value; however, the loss recognized will *not* exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity will consider income tax effects from any tax-deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

The amendments in ASU 2017-04 modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. An entity *no* longer will determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Because these amendments eliminate Step 2 from the goodwill impairment test, they should reduce the cost and complexity of evaluating goodwill for impairment. The amendments in ASU 2017-04 are effective for annual or any interim goodwill impairment tests in fiscal years beginning after *December 15, 2019*. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after *January 1, 2017*.

ASU 2018-02—In February 2018 the FASB issued ASU No. 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). The amendments in ASU 2018-02, which are narrow in scope, allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. Consequently, the amendments eliminate the stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act (TCJA) and will improve the usefulness of information reported to financial statement users. The amendments in ASU 2018-02 also require certain disclosures about stranded tax effects and are effective for fiscal years beginning after *December 15, 2018*, and interim periods within those fiscal years. Early adoption of the amendments in ASU 2018-02 is permitted. The amendments in ASU 2018-02 can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. The Company does *not* plan to adopt the amendments in ASU 2018-02 until the *first* quarter of 2019. On adoption, the Company will reclassify the \$784,000 of income tax effects of the TCJA on the gross deferred tax amounts at the date of enactment of the TCJA related to items remaining in accumulated other comprehensive income from other comprehensive income to retained earnings so that the remaining gross deferred tax amounts related to items in other comprehensive income will reflect current effective tax rates.

2. Segment Information

Segment Information

The accounting policies of the segments are described under note 1 – Summary of Significant Accounting Policies. The Company's businesses have been classified into *three* segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision makers. These businesses sell products and provide services to customers primarily in the United States. The Company's business structure currently includes the following *three* segments: Electric, Manufacturing and Plastics. The chart below indicates the companies included in each segment.

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Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the upper Midwest and Southwest regions of the United States.

OTP is a wholly owned subsidiary of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar). The Company's Corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is *not* an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

No single customer accounted for over 10% of the Company's consolidated revenues in 2017. The Electric segment has *one* customer that provided 11.7% of 2017 Electric segment revenues. The Manufacturing segment has *one* customer that manufactures and sells recreational vehicles that provided 24.3% of 2017 Manufacturing segment revenues and *one* customer that manufactures and sells lawn and garden equipment that provided 12.0% of 2017 Manufacturing segment revenues. The Plastics segment has *two* customers that individually provided 20.6% and 17.8% of 2017 Plastics segment revenues. The loss of any *one* of these customers would have a significant negative impact on the financial position and results of operations of the respective business segment and the Company.

All of the Company's long-lived assets are within the United States and 98.3% and 98.4% of its operating revenues for the respective *three*-month periods ended *March 31, 2018* and *2017* came from sales within the United States.

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for the *three* months ended *March 31, 2018* and *2017* and total assets by business segment as of *March 31, 2018* and *December 31, 2017* are presented in the following tables:

Operating Revenue

<i>(in thousands)</i>	Three Months Ended	
	2018	2017
Electric Segment:		
Retail Sales Revenue from Contracts with Customers	\$109,180	\$106,454
Changes in Accrued ARP Revenues	(875)	(1,239)
Total Retail Sales Revenue	108,305	105,215
Wholesale Revenues – Company Generation	1,015	867
Other Revenues	13,645	12,469
Total Electric Segment Revenues	\$122,965	\$118,551
Manufacturing Segment:		
Metal Parts and Tooling	\$56,927	\$48,078
Plastic Products	10,235	9,552
Other	1,500	787
Total Manufacturing Segment Revenues	\$68,662	\$58,417
Plastics Segment – Sale of PVC Pipe Products	\$49,653	\$37,157
Intersegment Eliminations	\$(14)	\$(8)
Total	\$241,266	\$214,117

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<i>(in thousands)</i>	Three Months Ended March 31,	
	2018	2017
Electric	\$6,390	\$6,386
Manufacturing	554	554
Plastics	150	153
Corporate and Intersegment Eliminations	278	369
Total	\$7,372	\$7,462

Income Taxes

<i>(in thousands)</i>	Three Months Ended March 31,	
	2018	2017
Electric	\$2,098	\$6,062
Manufacturing	1,223	1,055
Plastics	2,414	1,390
Corporate	(1,941)	(2,144)
Total	\$3,794	\$6,363

Net Income (Loss)

<i>(in thousands)</i>	Three Months Ended March 31,	
	2018	2017
Electric	\$16,668	\$15,560
Manufacturing	4,164	2,172
Plastics	6,844	2,437
Corporate	(1,461)	(640)
Discontinued Operations	--	56
Total	\$26,215	\$19,585

Identifiable Assets

	March 31,	December
<i>(in thousands)</i>	2018	31, 2017
Electric	\$1,686,255	\$1,690,224
Manufacturing	180,319	167,023
Plastics	97,953	87,230
Corporate	42,891	59,801
Total	\$2,007,418	\$2,004,278

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3. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP's revenues in 2018 and 2017.

Major Capital Expenditure Projects

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345-kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in *December 2011*. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the *second* quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of *March 31, 2018* were approximately \$96.5 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power–Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in *December 2011*. Construction began on this line in the *third* quarter of 2015 and the line was energized on *September 8, 2017*. OTP's capitalized costs on this project as of *March 31, 2018* were approximately \$72.4 million, which includes assets that are 100% owned by OTP.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Minnesota

General Rates—The MPUC rendered its final decision in OTP's 2016 general rate case in *March 2017* and issued its written order on *May 1, 2017*. Pursuant to the order, OTP's allowed rate of return on rate base decreased from *8.61%* to *7.5056%* and its allowed rate of return on equity decreased from *10.74%* to *9.41%*.

The MPUC's order also included: (1) the determination that all costs (including FERC allocated costs and revenues) of the Big Stone South–Brookings and Big Stone South–Ellendale MVPs will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers, and (2) approval of OTP's proposal to transition rate base, expenses and revenues from ECR and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates will be used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

OTP accrued interim and rider rate refunds until final rates became effective. The final interim rate refund, including interest, of \$9.0 million was applied as a credit to Minnesota customers' electric bills beginning *November 17, 2017*. In addition to the interim rate refund, OTP will refund the difference between (1) amounts collected under its Minnesota ECR and TCR riders based on the return on equity (ROE) approved in its most recent rider update and (2) amounts that would have been collected based on the lower *9.41%* ROE approved in its 2016 general rate case going back to *April 16, 2016*, the date interim rates were implemented. As of *October 31, 2017*, the revenues collected under the Minnesota ECR and TCR riders subject to refund due to the lower ROE rate and other adjustments were \$0.9 million and \$1.4 million, respectively. These amounts are being refunded to Minnesota customers over a 12-month period through reductions in the Minnesota ECR and TCR rider rates in effect *November 1, 2017*, as approved by the MPUC. The TCR rate is provisional and subject to revision under a separate docket.

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Minnesota Conservation Improvement Programs (MNCIP)—OTP recovers conservation related costs *not* included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC. On *May 25, 2016* the MPUC adopted the Minnesota Department of Commerce's (MNDOC's) proposed changes to the MNCIP financial incentive. The model provides utilities an incentive of *13.5%* of *2017* net benefits, *12%* of *2018* net benefits and *10%* of *2019* net benefits, assuming the utility achieves *1.7%* savings compared to retail sales. The financial incentive is also limited to *40%* of *2017* MNCIP spending, *35%* of *2018* spending and *30%* of *2019* spending.

Based on results from the *2017* MNCIP program year, OTP recognized a financial incentive of *\$2.6* million in *2017*. The *2017* program resulted in an approximate *10%* decrease in energy savings compared to *2016* program results. OTP requested approval for recovery of its *2017* MNCIP program costs *not* included in base rates, a *\$2.6* million financial incentive and an update to the MNCIP surcharge from the MPUC on *March 31, 2018*.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that meet certain criteria, plus a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC *may* approve annual rate adjustments filed pursuant to the rate schedule.

In OTP's *2016* general rate case order issued on *May 1, 2017*, the MPUC ordered OTP to include, in the TCR rider retail rate base, Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment will result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the *two* jurisdictions at any given time. On *August 18, 2017* OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to jurisdictionally allocate costs of the FERC MVP transmission projects in the TCR rider. On *March 22, 2018* oral arguments were made before the Minnesota Court of Appeals. A decision is anticipated by the end of the *second* quarter *2018*. OTP believes the MPUC-ordered treatment conflicts with federal authority over interstate transmission of electricity in and with FERC electric transmission rates as set forth in the Federal Power Act of *1935*, as amended (Federal Power Act).

Environmental Cost Recovery Rider— OTP had an ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant Air Quality Control System (AQCS). The ECR rider provided for a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's *2010* general rate case. In its *2016* general rate case order, the MPUC approved OTP's proposal to transition eligible rate base and expense recovery from the ECR rider to base rate recovery, effective with implementation of final rates in *November 2017*.

Renewable Resource Adjustment— Effective *November 1, 2017*, with the implementation of final rates in Minnesota, new rates were put into effect for the Minnesota RRA rider to address recovery of federal Production Tax Credits (PTCs) expiring on OTP's wind farms in *2017* and *2018*.

North Dakota

General Rates—On *November 2, 2017* OTP filed a request with the NDPSC for a rate review and an effective increase in annual revenues from non-fuel base rates of *\$13.1* million or *8.72%*. The *\$13.1* million increase is net of reductions in North Dakota RRA, TCR and ECR rider revenues that will result from a lower allowed rate of return on equity and changes in allocation factors in the general rate case. In the request, OTP proposed an allowed return on rate base of *7.97%* and an allowed rate of return on equity of *10.30%*. On *December 20, 2017* the NDPSC approved OTP's request for interim rates to increase annual revenue collections by *\$12.8* million, effective *January 1, 2018*. OTP used the same rate of return on equity in the calculation of interim rates as the rate of return on equity used in its *2018* test-year rate request. In response to the reduction in the federal corporate tax rate under the TCJA, the NDPSC issued an order on *February 27, 2018* reducing OTP's annual revenue requirement for interim rates by *\$4.5* million to *\$8.3* million, effective *March 1, 2018*. On *March 23, 2018* OTP made a supplemental filing to its initial request for a rate review, reducing its request for an annual revenue increase from *\$13.1* million to *\$7.1* million, a *4.8%* annual increase. The *\$6.0* million decrease includes *\$4.8* million related to tax reform and *\$1.2* million related to other updates. OTP will continue to address the impacts of the TJCA in its current general rate case.

OTP's most recently approved general rate increase in North Dakota of *\$3.6* million, or approximately *3.0%*, was granted by the NDPSC in an order issued on *November 25, 2009* and effective *December 2009*. Pursuant to the order, OTP's allowed rate of return on rate base was set at *8.62%*, and its allowed rate of return on equity was set at *10.75%*.

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Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment which enables OTP to recover its North Dakota jurisdictional share of investments in renewable energy facilities. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxic Standards (MATS) projects. The ECR rider provides for a return on investment at the level approved in OTP's most recent general rate case and for recovery of OTP's North Dakota share of reagent and emission allowance costs.

South Dakota

General Rates—On *April 20, 2018* OTP filed a request with the SDPUC to increase non-fuel rates in South Dakota by approximately \$3.3 million annually, or *10.1%*, as the *first* step in a *two*-step request. OTP requested an interim rate increase effective *May 21, 2018* while the SDPUC considers OTP's overall request. The SDPUC is scheduled to review the application and act on the request for interim rates on *May 15, 2018*. The full effects of the TCJA on South Dakota revenue requirements will be addressed in OTP's current general rate case and incorporated into final rates at the conclusion of that case. The *second* step in the request is an additional *1.7%* increase to be effective *January 1, 2020* to recover costs for a wind generation facility scheduled to be in service by the end of *2019*.

OTP's most recently approved general rate increase in South Dakota of approximately \$643,000 or approximately 2.32% was granted by the SDPUC in an order issued on *April 21, 2011* and effective with bills rendered on and after *June 1, 2011*. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities.

Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects.

Reagent Costs and Emission Allowances—The SDPUC has approved the recovery of reagent and emission allowance costs in OTP's South Dakota Fuel Clause Adjustment rider.

Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the *three*-month periods ended *March 31*:

Rate Rider (<i>in thousands</i>)	2018	2017
Minnesota		
Conservation Improvement Program Costs and Incentives ¹	\$2,516	\$1,966
Transmission Cost Recovery	(29)	2,170
Environmental Cost Recovery	(31)	2,824
Renewable Resource Recovery	525	--
North Dakota		
Renewable Resource Adjustment	1,967	1,770
Transmission Cost Recovery	2,062	2,511
Environmental Cost Recovery	1,821	2,488
South Dakota		
Transmission Cost Recovery	536	441
Environmental Cost Recovery	520	597
Conservation Improvement Program Costs and Incentives	229	240
Total	\$10,116	\$15,007

¹Includes MNCIP costs recovered in base rates.

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The following table provides summary information on the status of updates since *January 1, 2016* for the rate riders described above:

Rate Rider	R - Request Date	Effective Date	Annual	
	A - Approval Date	Requested or Approved	Revenue	Rate
Minnesota				
Conservation Improvement Program				
2017 Incentive and Cost Recovery	R – March 31, 2018	October 1, 2018	\$ 10,400	\$0.00600/kwh
2016 Incentive and Cost Recovery	A – September 15, 2017	October 1, 2017	\$ 9,868	\$0.00536/kwh
2015 Incentive and Cost Recovery	A – July 19, 2016	October 1, 2016	\$ 8,590	\$0.00275/kwh
Transmission Cost Recovery				
2017 Rate Reset ¹	A – October 30, 2017	November 1, 2017	\$(3,311)	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	\$ 4,736	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	\$ 7,203	Various
Environmental Cost Recovery				
2017 Rate Reset	A – October 30, 2017	November 1, 2017	\$(1,943)	-0.935% of base
2016 Annual Update	A – July 5, 2016	September 1, 2016	\$ 11,884	6.927% of base
Renewable Resource Adjustment				
2017 Rate Reset	A – October 30, 2017	November 1, 2017	\$ 1,279	\$0.00049/kwh
North Dakota				
Renewable Resource Adjustment				
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	\$ 9,650	7.493% of base
2017 Rate Reset	A – December 20, 2017	January 1, 2018	\$ 9,989	7.756% of base
2016 Annual Update	A – March 15, 2017	April 1, 2017	\$ 9,156	7.005% of base
2015 Annual Update	A – June 22, 2016	July 1, 2016	\$ 9,262	7.573% of base
Transmission Cost Recovery				
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	\$ 7,469	Various
2017 Annual Update	A – November 29, 2017	January 1, 2018	\$ 7,959	Various
2016 Annual Update	A – December 14, 2016	January 1, 2017	\$ 6,916	Various
Environmental Cost Recovery				
2018 Rate Reset for effect of TCJA	A – February 27, 2018	March 1, 2018	\$ 7,718	5.593% of base
2017 Rate Reset	A – December 20, 2017	January 1, 2018	\$ 8,537	6.629% of base
2017 Annual Update	A – July 12, 2017	August 1, 2017	\$ 9,917	7.633% of base
2016 Annual Update	A – June 22, 2016	July 1, 2016	\$ 10,359	7.904% of base
South Dakota				
Transmission Cost Recovery				
2017 Annual Update	A – February 28, 2018	March 1, 2018	\$ 1,779	Various
2016 Annual Update	A – February 17, 2017	March 1, 2017	\$ 2,053	Various
2015 Annual Update	A – February 12, 2016	March 1, 2016	\$ 1,895	Various

Environmental Cost Recovery

2017 Annual Update	A – October 13, 2017	November 1, 2017	\$2,082	\$0.00483/kwh
2016 Annual Update	A – October 26, 2016	November 1, 2016	\$2,238	\$0.00536/kwh

¹Approved on a provisional basis in the Minnesota general rate case docket and subject to revision in a separate docket.

TCJA

The TCJA reduced the federal corporate income tax rate from 35% to 21%. Currently, all OTP rates have been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC have all initiated dockets or proceedings to assess the impact of the lower income tax rates under the TCJA on electric rates and develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required regulated utilities providing service in Minnesota to make filings by *February 15, 2018* but has *not* made a determination on rate treatment. The SDPUC required initial comments by *February 1, 2018* and indicated that revenues collected after *December 31, 2017* would be subject to refund, pending determination of the impacts of the TCJA. As described above, OTP's pending general rate cases in North Dakota and South Dakota reflect the impact of the TCJA. OTP has accrued refund liabilities for revenues collected under rates set to recover higher levels of federal income taxes than OTP is currently incurring under the lower federal tax rates in the TCJA. The accrued refund liabilities as of *March 31, 2018* related to the tax rate reduction were \$1.9 million in Minnesota, \$0.8 million in North Dakota and \$0.5 million in South Dakota.

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FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a *one*-day suspension period, subject to ultimate approval by the FERC.

MVPs—On *December 16, 2010* the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit.

On *November 12, 2013* a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, *may* collect under the MISO Tariff. The complainants sought to reduce the *12.38%* ROE used in MISO's transmission rates to a proposed *9.15%*. The complaint established a *15*-month refund period from *November 12, 2013* to *February 11, 2015*. A non-binding decision by the presiding Administrative Law Judge (ALJ) was issued on *December 22, 2015* finding that the MISO transmission owners' ROE should be *10.32%*, and the FERC issued an order on *September 28, 2016* setting the base ROE at *10.32%*. A number of parties requested rehearing of the *September 2016* order and the requests are pending FERC action.

On *November 6, 2014* a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional *50*-basis points for Regional Transmission Organization participation (RTO Adder). On *January 5, 2015* the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the *November 12, 2013* complaint and OTP's incentive rate filing, OTP's ROE will be *10.82%* (a *10.32%* base ROE plus the *0.5%* RTO Adder) effective *September 28, 2016*.

On *February 12, 2015* another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, *may* collect under the MISO Tariff from *12.38%* to a proposed *8.67%*. This *second* complaint established a *second 15*-month refund period from *February 12, 2015* to *May 11, 2016*. The FERC issued an order on *June 18, 2015* setting the complaint for hearings before an ALJ, which were held the week of *February 16, 2016*. A non-binding decision by the presiding ALJ was issued on *June 30, 2016* finding that the MISO transmission owners' ROE should be *9.7%*. OTP is currently waiting for the issuance of a FERC order on the *second* complaint.

Based on the probable reduction by the FERC in the ROE component of the MISO Tariff, OTP had a \$2.7 million liability on its balance sheet as of *December 31, 2016*, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE. MISO processed the refund for the FERC-ordered reduction in the MISO Tariff allowed ROE for the *first 15-month* refund period in its *February* and *June 2017* billings. The refund, in combination with a decision in the *2016* Minnesota general rate case that affected the Minnesota TCR rider, has resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from \$2.7 million on *December 31, 2016* to \$1.6 million as of *March 31, 2018*.

In *June 2014*, the FERC adopted a *two-step* ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the *two* ROE complaints involving MISO transmission owners discussed above. In *April 2017* the Court of Appeals for the District of Columbia (D.C. Circuit) vacated and remanded the FERC's *June 2014* ROE order in the NETOs' complaint. The D.C. Circuit found that the FERC had *not* properly determined that the ROE authorized for NETOs prior to *June 2014* was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. OTP will await the FERC response to the *April 2017* action of the D.C. Circuit before determining if an adjustment to its accrued refund liability is required. On *September 29, 2017* the MISO transmission owners filed a motion to dismiss the *second* complaint based on the D.C. Circuit decision in the NETOs complaint. If FERC were to act on a motion to dismiss, it would eliminate the refund obligation from the *second* complaint and the ROE from the *first* complaint would remain in effect.

Table of Contents**4. Regulatory Assets and Liabilities**

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC Topic 980, *Regulated Operations* (ASC 980). This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources, environmental upgrades and conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

<i>(in thousands)</i>	March 31, 2018			Remaining Recovery/ Refund Period (months)
	Current	Long-Term	Total	
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹	\$9,090	\$110,214	\$119,304	see below
Conservation Improvement Program Costs and Incentives ²	5,313	3,468	8,781	30
Accumulated ARO Accretion/Depreciation Adjustment ¹	--	6,779	6,779	asset lives
Deferred Marked-to-Market Losses ¹	3,463	1,989	5,452	33
Big Stone II Unrecovered Project Costs – Minnesota ⁴	657	1,467	2,124	37
Debt Reacquisition Premiums ¹	246	904	1,150	174
Big Stone II Unrecovered Project Costs – South Dakota ⁴	100	417	517	62
North Dakota Deferred Rate Case Expenses Subject to Recovery ¹	374	--	374	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues ¹	322	--	322	12
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery ¹	--	196	196	asset lives
Minnesota Southwest Power Pool Transmission Cost Recovery Tracker ¹	--	166	166	see below
North Dakota Transmission Cost Recovery Rider Accrued Revenues ²	133	--	133	21
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ¹	--	67	67	21
Minnesota Deferred Rate Case Expenses Subject to Recovery ¹	38	--	38	1
Total Regulatory Assets	\$19,736	\$125,667	\$145,403	
Regulatory Liabilities:				
Deferred Income Taxes	\$--	\$148,938	\$148,938	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	84,223	84,223	asset lives
Refundable Fuel Clause Adjustment Revenues	2,414	--	2,414	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,161	--	1,161	7
North Dakota Renewable Resource Recovery Rider Accrued Refund	371	--	371	9
North Dakota Environmental Cost Recovery Rider Accrued Refund	351	--	351	12
South Dakota Environmental Cost Recovery Rider Accrued Refund	317	--	317	12

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Minnesota Renewable Resource Recovery Rider Accrued Refund	304	--	304	7
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	68	36	104	21
Other	6	82	88	189
South Dakota Transmission Cost Recovery Rider Accrued Refund	60	--	60	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	37	--	37	7
Revenue for Rate Case Expenses Subject to Refund – Minnesota	30	--	30	1
Total Regulatory Liabilities	\$5,119	\$233,279	\$238,398	
Net Regulatory Asset/(Liability) Position	\$14,617	\$(107,612)	\$(92,995)	

¹Costs subject to recovery excluding a rate of return.

²Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

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<i>(in thousands)</i>	December 31, 2017			Remaining Recovery/ Refund Period (months)
	Current	Long-Term	Total	
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹	\$9,090	\$112,487	\$121,577	see below
Conservation Improvement Program Costs and Incentives ²	7,385	2,774	10,159	21
Accumulated ARO Accretion/Depreciation Adjustment ¹	--	6,651	6,651	asset lives
Deferred Marked-to-Market Losses ¹	4,063	2,405	6,468	36
Big Stone II Unrecovered Project Costs – Minnesota ¹	650	1,636	2,286	40
Debt Reacquisition Premiums ¹	254	960	1,214	177
Big Stone II Unrecovered Project Costs – South Dakota	100	442	542	65
North Dakota Deferred Rate Case Expenses Subject to Recovery ¹	309	--	309	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues ¹	75	--	75	12
North Dakota Renewable Resource Rider Accrued Revenues ²	206	236	442	15
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ¹	--	1,985	1,985	24
Minnesota Deferred Rate Case Expenses Subject to Recovery ¹	267	--	267	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues ²	152	--	152	12
Total Regulatory Assets	\$22,551	\$129,576	\$152,127	
Regulatory Liabilities:				
Deferred Income Taxes	\$--	\$149,052	\$149,052	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	83,100	83,100	asset lives
Refundable Fuel Clause Adjustment Revenues	5,778	--	5,778	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,667	--	1,667	11
South Dakota Environmental Cost Recovery Rider Accrued Refund	187	--	187	12
Minnesota Renewable Resource Recovery Rider Accrued Refund	409	--	409	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	48	180	24
Other	5	84	89	192
South Dakota Transmission Cost Recovery Rider Accrued Refund	151	--	151	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	802	--	802	10
Revenue for Rate Case Expenses Subject to Refund – Minnesota	208	--	208	4
Minnesota Southwest Power Pool Transmission Cost Tracker Refund	--	609	609	22
North Dakota Transmission Cost Recovery Rider Accrued Refund	349	--	349	12
Total Regulatory Liabilities	\$9,688	\$232,893	\$242,581	
Net Regulatory Asset/(Liability) Position	\$12,863	\$(103,317)	\$(90,454)	

¹Costs subject to recovery excluding a rate of return.

²Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC Topic 715, *Compensation—Retirement Benefits*, but are eligible for treatment as regulatory assets based on their probable

recovery in future retail electric rates.

Conservation Improvement Program Costs and Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates.

The Accumulated Asset Retirement Obligation (ARO) Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

All Deferred Marked-to-Market Losses recorded as of *March 31, 2018* relate to forward purchases of energy scheduled for delivery through *December 2020*.

Big Stone II Unrecovered Project Costs – Minnesota are the Minnesota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is *174* months.

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Big Stone II Unrecovered Project Costs – South Dakota are the South Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

North Dakota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's current rate case in North Dakota and are currently being recovered beginning with the establishment of interim rates in *January 2018*.

Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues relate to revenues recorded for fuel and purchased power costs reductions provided to customers in energy intensive trade exposed industries that are subject to recovery from other Minnesota customers.

The Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery are employee benefit-related costs that are required to be capitalized for ratemaking purposes and are recovered over the depreciable lives of the assets to which the related labor costs were applied.

The Minnesota Southwest Power Pool Transmission Cost Recovery Tracker relates to costs incurred, in excess of the rate at which the costs are being recovered under current rates, that are subject to future recovery under current rates or through future rate adjustments.

North Dakota Transmission Cost Recovery Rider Accrued Revenues relate to amounts recoverable for investments in qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that have *not* been billed to North Dakota customers as of *March 31, 2018*.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that had *not* been billed to North Dakota customers as of *December 31, 2017*.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-ups relate to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-ups also include the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota currently being recovered over a 24-month period beginning with the establishment of interim rates in *April 2016*.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and for reagent and emission allowances costs that had *not* been billed to North Dakota customers as of *December 31, 2017*.

The regulatory liability related to Deferred Income Taxes results from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes*.

The Accumulated Reserve for Estimated Removal Costs – Net of Salvage is reduced as actual removal costs, net of salvage revenues, are incurred.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of *March 31, 2018*.

The North Dakota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of *March 31, 2018*.

The North Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and for reagent and emission allowances costs that are recoverable from North Dakota customers as of *March 31, 2018*.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of *March 31, 2018*.

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The Minnesota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of *March 31, 2018*.

The South Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that are refundable to South Dakota customers as of *March 31, 2018*.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of *March 31, 2018*.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relates to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund over a 24-month period beginning with the establishment of interim rates in *April 2016*.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of *March 31, 2018*.

The Minnesota Southwest Power Pool Transmission Cost Tracker Refund relates to revenues billed for recovery of these transmission costs in excess of actual costs incurred that are subject to refund.

If for any reason OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that *no* longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Reconciliation of Common Shareholders' Equity, Common Shares and Earnings Per Share

Reconciliation of Common Shareholders' Equity

<i>(in thousands)</i>	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Equity
Balance, December 31, 2017	\$197,787	\$343,450	\$161,286	\$ (5,631)) \$696,892
Common Stock Issuances, Net of Expenses	638	(638)			--
Common Stock Retirements	(292)	(2,117)			(2,409)
Net Income			26,215		26,215
Other Comprehensive Loss				(502)	(502)
Employee Stock Incentive Plans Expense		1,146			1,146
Common Dividends (\$0.335 per share)			(13,292)		(13,292)
Balance, March 31, 2018	\$198,133	\$341,841	\$174,209	\$ (6,133)) \$708,050

Shelf Registrations and Common Share Distribution Agreement

On *May 3, 2018* the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which we *may* offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on *May 3, 2021*. On *May 3, 2018*, the Company also filed a shelf registration statement with the SEC for the issuance of up to *1,500,000* common shares under the Company's Automatic Dividend Reinvestment (DRIP) and Share Purchase Plan (the Plan), which permits shares purchased by participants in the Plan to be either new issue common shares or common shares purchased in the open market. The shelf registration for the DRIP expires on *May 3, 2021*. The shelf registration statements replaced the Company's prior shelf registration statements that were due to expire on *May 11, 2018*. On *May 1, 2018* the Company's Distribution Agreement with J.P. Morgan Securities (JPMS) ended as required under the agreement. This Distribution Agreement allowed the Company to offer and sell its common shares from time to time in an At-the-Market (ATM) offering program through JPMS, up to an aggregate sales price of \$75 million. The Company expects to establish a new ATM offering program under which the Company *may* offer and sell its common shares from time to under the shelf registration statement.

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Following is a reconciliation of the Company's common shares outstanding from *December 31, 2017* through *March 31, 2018*:

Common Shares Outstanding, December 31, 2017	39,557,491
Issuances:	
Executive Stock Performance Awards (2015 shares earned)	114,648
Vesting of Restricted Stock Units	12,950
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(58,495)
Common Shares Outstanding, March 31, 2018	39,626,594

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the *three-month* periods ended *March 31, 2018* and *2017*. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company's directors and employees, which are considered contingently returnable and *not* outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting basic shares outstanding for the items listed in the following reconciliation for the *three-month* periods ended *March 31*:

	2018	2017
Weighted Average Common Shares Outstanding – Basic	39,550,874	39,350,802
Plus Outstanding Share Awards net of Share Reductions for Unrecognized Stock-Based Compensation Expense and Excess Tax Benefits:		
Shares Expected to be Awarded for Stock Performance Awards Granted to Executive Officers based on Measurement Period-to-Date Performance	223,162	201,639
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	59,130	57,873
Nonvested Restricted Shares	27,643	27,069
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	2,873	3,342
Total Dilutive Shares	312,808	289,923
Weighted Average Common Shares Outstanding – Diluted	39,863,682	39,640,725

The effect of dilutive shares on earnings per share for the *three-month* periods ended *March 31, 2018* and *2017*, resulted in *no* differences greater than *\$0.01* between basic and diluted earnings per share in total or from continuing or discontinued operations in either period.

6. Share-Based Payments

Stock Incentive Awards

On *February 5, 2018* the following stock incentive awards were granted to officers under the *2014* Stock Incentive Plan:

Award	Shares/Units Granted	Weighted	Vesting
		Average Grant- Date Fair Value	
Restricted Stock Units Granted	15,200	per Award \$ 41.325	25% per year through February 6, 2022
Stock Performance Awards Granted	54,000	\$ 35.73	December 31, 2020

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration in certain cases. All restricted stock units granted to executive officers are eligible to receive dividend equivalent payments on all unvested awards over the awards' respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The grant-date fair value of each restricted stock unit was the average of the high and low market price per share on the date of grant.

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Under the performance share awards the aggregate award for performance at target is 54,000 shares. For target performance the participants would earn an aggregate of 27,000 common shares for achieving the target set for the Company's 3-year average adjusted return on equity. The participants would also earn an aggregate of 27,000 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance measurement period of *January 1, 2018* through *December 31, 2020*, with the beginning and ending share values based on the average closing price of a share of the Company's common stock for the 20 trading days immediately following *January 1, 2018* and the average closing price for the 20 trading days immediately preceding *January 1, 2021*. Actual payment may range from zero to 150% of the target amount, or up to 81,000 common shares. There are no voting or dividend rights related to these awards until the shares, if any, are issued at the end of the performance measurement period. The amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to an officer who is party to an Executive Employment Agreement with the Company is to be made at target at the date of any such event. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC 718, and will be measured over the performance period based on the grant-date fair value of the award. The grant-date fair value of each performance share award was determined using a Monte Carlo fair valuation simulation model.

The end of the period over which compensation expense is recognized for the above share-based awards for the individual grantees is the shorter of the indicated vesting period for the respective awards or the date the grantee becomes eligible for retirement as defined in their award agreement.

As of *March 31, 2018*, the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately \$5.9 million (before income taxes) which will be amortized over a weighted-average period of 2.2 years.

Amounts of compensation expense recognized under the Company's six stock-based payment programs for the three-month periods ended *March 31, 2018* and *2017* are presented in the table below:

<i>(in thousands)</i>	Three months ended	
	2018	2017
Stock Performance Awards Granted to Executive Officers	\$651	\$649
Restricted Stock Units Granted to Executive Officers	249	264
Restricted Stock Granted to Executive Officers	16	22
Restricted Stock Granted to Directors	166	128
Restricted Stock Units Granted to Non-Executive Employees	64	87
Totals	\$1,146	\$1,150

7. Retained Earnings and Dividend Restriction

The Company is a holding company with *no* significant operations of its own. The primary source of funds for payments of dividends to the Company's shareholders is from dividends paid or distributions made by the Company's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by the Company's subsidiaries.

Both the Company and OTP credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if the Company did *not* meet certain financial covenants. As of *March 31, 2018*, the Company was in compliance with these financial covenants. See note 9 to consolidated financial statements for further information on the covenants.

Under the Federal Power Act, a public utility *may not* pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is *not* excessive and (3) there is *no* self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between *47.4%* and *58.0%* based on OTP's *2017* capital structure petition approved by order of the MPUC on *September 1, 2017*. As of *March 31, 2018*, OTP's equity-to-total-capitalization ratio including short-term debt was *51.6%* and its net assets restricted from distribution totaled approximately *\$481,000,000*. Total capitalization for OTP cannot currently exceed *\$1,178,024,000*.

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8. Commitments and Contingencies

Construction and Other Purchase Commitments

At *March 31, 2018* OTP had commitments under contracts, including its share of construction program commitments, extending into *2019* of approximately \$37.5 million. At *December 31, 2017* OTP had commitments under contracts, including its share of construction program commitments, extending into *2019* of approximately \$41.0 million. At *March 31, 2018* T.O. Plastics had commitments for the purchase of resin through *December 31, 2021* of approximately \$6.2 million. At *December 31, 2017* T.O. Plastics had commitments for the purchase of resin through *December 31, 2021* of approximately \$6.7 million.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into *2041*. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Big Stone Plant and Coyote Station expire at the end of *2019* and *2040*, respectively. OTP has an agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through *December 31, 2023*. OTP has *no* fixed minimum purchase requirements under the agreement but all of Hoot Lake Plant's coal requirements for the period covered must be purchased under this agreement.

Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. In the *first* quarter of *2018*, OTP entered into an agreement to lease rail cars for transporting coal to Hoot Lake Plant. The lease period runs from *April 2018* through *May 2021*, increasing OTP's commitments under operating leases by \$243,000 in *2018*, \$324,000 in *2019*, \$324,000 in *2020* and \$135,000 in *2021*. The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment.

Contingencies

OTP had a \$1.6 million refund liability on its balance sheet as of *March 31, 2018* representing its best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on the likelihood of the FERC reducing the ROE component of the MISO Tariff and ordering MISO to refund amounts charged in excess of the lower rate.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on *April 1, 2005* until the conclusion of the proceedings on *May 2, 2015*. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders, and the FERC's decision to *not* resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. OTP is an intervenor in these cases. Final briefs were filed on *January 26, 2018*. Oral arguments occurred on *May 2, 2018*. A final decision is anticipated in the summer of 2018. MISO has *not* made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, the Company cannot estimate OTP's exposure at this time from a final order reversing the relevant FERC orders, which could have an adverse effect on the Company's results of operations.

Contingencies, by their nature, relate to uncertainties that require the Company's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. In addition to the ROE refund described earlier, the most significant contingencies impacting the Company's consolidated financial statements are those related to environmental remediation, risks associated with warranty claims relating to divested businesses that could exceed the established reserve amounts and litigation matters. Should all of these known items, excluding the ROE refund liability already recognized, result in liabilities being incurred, the loss could be as high as \$1.0 million, excluding any liability for RSG charges for which an estimate cannot be made at this time.

In 2014 the Environmental Protection Agency (EPA) published both proposed standards of performance for carbon dioxide (CO₂) emissions from new, reconstructed and modified fossil fuel-fired power plants (New Source Performance Standards), and proposed CO₂ emission guidelines for existing fossil fuel-fired power plants (the Clean Power Plan) under Section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on *October 23, 2015*. Both rules were challenged on legal grounds. On *February 9, 2016* the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review in the D.C. Circuit. The D.C. Circuit heard oral argument on challenges to the Clean Power Plan on *September 27, 2016* before the full court, and a decision was expected in the *first* half of 2017. However, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, the EPA was directed to consider suspending, revising

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or rescinding the *CO2* rules discussed above. Thereafter, the EPA issued notices in the Federal Register of its intent to review these rules pursuant to the Executive Order, and it filed motions to stay the pending litigation. The D.C. Circuit subsequently issued orders holding in abeyance the appeals of both the New Source Performance Standards and the Clean Power Plan, pending EPA review. On *October 16, 2017* the EPA published a proposed rule to rescind the Clean Power Plan. Therefore, there is uncertainty regarding the future of both rules.

Other

The Company is a party to litigation and regulatory enforcement matters arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of *March 31, 2018* will *not* be material.

9. Short-Term and Long-Term Borrowings

The following table presents the status of the Company's lines of credit as of *March 31, 2018* and *December 31, 2017*:

<i>(in thousands)</i>	Line Limit	In Use on March 31, 2018	Restricted due to Outstanding Letters of Credit	Available on March 31, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	\$130,000	\$6,182	\$ --	\$123,818	\$130,000
OTP Credit Agreement	170,000	24,137	300	145,563	57,239
Total	\$300,000	\$30,319	\$ 300	\$269,381	\$187,239

Debt Issuances2018 Note Purchase Agreement

On *November 14, 2017*, OTP entered into a Note Purchase Agreement (the *2018 Note Purchase Agreement*) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, \$100 million aggregate principal amount of OTP's 4.07% Series 2018A Senior Unsecured Notes due *February 7, 2048* (the *2018 Notes*). The *2018 Notes* were issued on *February 7, 2018*. Proceeds from the *2018 Notes* were used to repay outstanding borrowings under the OTP Credit Agreement.

OTP *may* prepay all or any part of the Notes (in an amount *not* less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount; provided that if *no* default or event of default exists under the Note Purchase Agreement, any prepayment made by OTP of all of the Notes then outstanding on or after *August 7, 2047* will be made without any make-whole amount. The *2018 Note Purchase Agreement* also requires OTP to offer to prepay all outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the *2018 Note Purchase Agreement*) of OTP.

The *2018 Note Purchase Agreement* contains a number of restrictions on the business of OTP. These include restrictions on OTP's abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The *2018 Note Purchase Agreement* also contains other negative covenants and events of default, as well as certain financial covenants. The *2018 Note Purchase Agreement* does *not* include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The *2018 Note Purchase Agreement* includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is *not* contained in the *2018 Note Purchase Agreement* under substantially similar terms or would be more beneficial to the holders of the *2018 Notes* than any analogous provision contained in the *2018 Note Purchase Agreement* (Additional Covenant), then unless waived by the Required Holders (as defined in the *2018 Note Purchase Agreement*), the Additional Covenant will be deemed to be incorporated into the *2018 Note Purchase Agreement*. The *2018 Note Purchase Agreement* also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that *no* default or event of default has occurred and is continuing.

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The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of *March 31, 2018* and *December 31, 2017*:

		OTTP	OTter Tail Corporation	OTter Tail Corporation Consolidated
March 31, 2018 (in thousands)				
Short-Term Debt		\$24,137	\$ 6,182	\$ 30,319
Long-Term Debt:				
3.55% Guaranteed Senior Notes, due December 15, 2026			\$ 80,000	\$ 80,000
Senior Unsecured Notes 4.63%, due December 1, 2021	\$140,000			140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000			60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000			90,000
Senior Unsecured Notes 4.07%, Series 2018A, due February 7, 2048	100,000			100,000
North Dakota Development Note, 3.95%, due April 1, 2018			7	7
PACE Note, 2.54%, due March 18, 2021			644	644
Total	\$512,000	\$ 80,651		\$ 592,651
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	171		171
Unamortized Long-Term Debt Issuance Costs	2,091	446		2,537
Total Long-Term Debt net of Unamortized Debt Issuance Costs	\$509,909	\$ 80,034		\$ 589,943
Total Short-Term and Long-Term Debt (with current maturities)	\$534,046	\$ 86,387		\$ 620,433

		OTTP	OTter Tail Corporation	OTter Tail Corporation Consolidated
December 31, 2017 (in thousands)				
Short-Term Debt		\$112,371	\$ --	\$ 112,371
Long-Term Debt:				
Term Loan, LIBOR plus 0.90%, due February 5, 2018			\$ --	\$ --
3.55% Guaranteed Senior Notes, due December 15, 2026			80,000	80,000
Senior Unsecured Notes 4.63%, due December 1, 2021	\$140,000			140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000			60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000			90,000
North Dakota Development Note, 3.95%, due April 1, 2018			27	27
PACE Note, 2.54%, due March 18, 2021			684	684

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Total	\$412,000	\$ 80,711	\$ 492,711
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	186	186
Unamortized Long-Term Debt Issuance Costs	1,684	461	2,145
Total Long-Term Debt net of Unamortized Debt Issuance Costs	\$410,316	\$ 80,064	\$ 490,380
Total Short-Term and Long-Term Debt (with current maturities)	\$522,687	\$ 80,250	\$ 602,937

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Table of Contents**10. Pension Plan and Other Postretirement Benefits**

Pension Plan—Components of net periodic pension benefit cost of the Company's noncontributory funded pension plan are as follows:

<i>(in thousands)</i>	Three Months Ended March 31,	
	2018	2017
Service Cost—Benefit Earned During the Period	\$1,615	\$1,407
Interest Cost on Projected Benefit Obligation	3,363	3,534
Expected Return on Assets	(5,300)	(4,807)
Amortization of Prior-Service Cost:		
From Regulatory Asset	4	30
From Other Comprehensive Income ¹	--	1
Amortization of Net Actuarial Loss:		
From Regulatory Asset	1,784	1,273
From Other Comprehensive Income ¹	44	31
Net Periodic Pension Cost ²	\$1,510	\$1,469
¹ Corporate cost included in nonservice cost components of postretirement benefits.		
² Allocation of Costs:		
Costs included in OTP capital expenditures	\$328	\$285
Service costs included in electric operation and maintenance expenses	1,247	1,100
Service costs included in other nonelectric expenses	40	34
Nonservice costs capitalized as regulatory assets	(21)	--
Nonservice costs included in nonservice cost components of postretirement benefits	(84)	50

Cash flows— The Company had *no* minimum funding requirement as of *December 31, 2017* but made discretionary plan contributions totaling \$20 million in the quarter ended *March 31, 2018*.

Executive Survivor and Supplemental Retirement Plan—Components of net periodic pension benefit cost of the Company's unfunded, nonqualified benefit plan for executive officers and certain key management employees are as follows:

<i>(in thousands)</i>	Three Months Ended March 31,	
	2018	2017

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Service Cost—Benefit Earned During the Period	\$100	\$73
Interest Cost on Projected Benefit Obligation	399	422
Amortization of Prior-Service Cost:		
From Regulatory Asset	4	4
From Other Comprehensive Income ¹	10	9
Amortization of Net Actuarial Loss:		
From Regulatory Asset	67	71
From Other Comprehensive Income ¹	165	110
Net Periodic Pension Cost ²	\$745	\$689

¹Amortization of prior service costs and net actuarial losses from other comprehensive income are included in nonservice cost components of postretirement benefits on the face of the Company's consolidated statements of income.

²Allocation of Costs:

Service costs included in electric operation and maintenance expenses	\$25	\$24
Service costs included in other nonelectric expenses	75	49
Nonservice costs included in nonservice cost components of postretirement benefits	645	616

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Postretirement Benefits—Components of net periodic postretirement benefit cost for health insurance and life insurance benefits for retired OTP and corporate employees, net of the effect of Medicare Part D Subsidy:

	Three Months Ended March 31,	
<i>(in thousands)</i>	2018	2017
Service Cost—Benefit Earned During the Period	\$382	\$356
Interest Cost on Projected Benefit Obligation	645	678
Amortization of Net Actuarial Loss:		
From Regulatory Asset	412	233
From Other Comprehensive Income ¹	10	6
Net Periodic Postretirement Benefit Cost ²	\$1,449	\$1,273
Effect of Medicare Part D Subsidy	\$(37)	\$(140)
¹ Corporate cost included in nonservice cost components of postretirement benefits.		
² Allocation of Costs:		
Costs included in OTP capital expenditures	\$78	\$247
Service costs included in electric operation and maintenance expenses	294	278
Service costs included in other nonelectric expenses	10	9
Nonservice costs capitalized as regulatory assets	217	--
Nonservice costs included in nonservice cost components of postretirement benefits	850	739

II. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash Equivalents—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of *March 31, 2018* and *December 31, 2017* related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to variable interest rates of LIBOR plus 1.50% and LIBOR plus 1.25%, respectively, which approximate market rates.

Long-Term Debt including Current Maturities—The fair value of the Company's and OTP's long-term debt is estimated based on the current market indications of rates available to the Company for the issuance of debt. The fair value measurements of the Company's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820.

<i>(in thousands)</i>	March 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	\$1,121	\$1,121	\$16,216	\$16,216
Short-Term Debt	(30,319)	(30,319)	(112,371)	(112,371)
Long-Term Debt including Current Maturities	(590,114)	(614,873)	(490,566)	(543,691)

Table of Contents**13. Income Tax Expense – Continuing Operations**

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on the Company's consolidated statements of income for the *three*-month periods ended *March 31, 2018* and *2017*:

<i>(in thousands)</i>	Three Months Ended March 31,	
	2018	2017
Income Before Income Taxes – Continuing Operations	\$30,009	\$25,892
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26% for first quarter 2018, 39% for first quarter 2017)	7,802	10,098
Increases (Decreases) in Tax from:		
Federal Production Tax Credits	(1,120)	(2,052)
Property Related Differences and Other Regulatory Adjustments	(1,073)	105
Excess Tax Deduction – Equity Method Stock Awards	(624)	(697)
Other Comprehensive Income Deferred Tax Rate Adjustment	(531)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(212)
Research and Development and Other Tax Credits	(180)	(157)
Allowance for Funds Used During Construction – Equity	(167)	(67)
Corporate Owned Life Insurance	(8)	(294)
Section 199 Domestic Production Activities Deduction	--	(330)
Other Items – Net	(47)	(31)
Income Tax Expense – Continuing Operations	\$3,794	\$6,363
Effective Income Tax Rate – Continuing Operations	12.6 %	24.6 %

The following table summarizes the activity related to the Company's unrecognized tax benefits:

<i>(in thousands)</i>	2018	2017
Balance on January 1	\$684	\$891
Decreases Related to Tax Positions for Prior Years	(44)	--
Increases Related to Tax Positions for Current Year	36	43
Uncertain Positions Resolved During Year	--	--
Balance on March 31	\$676	\$934

The balance of unrecognized tax benefits as of *March 31, 2018* would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of *March 31, 2018* is *not* expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as

components of the provision for income taxes in its consolidated statement of income. There was *no* amount accrued for interest on tax uncertainties as of *March 31, 2018*.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of *May 1, 2018*, with limited exceptions, the Company is *no* longer subject to examinations by taxing authorities for tax years prior to *2014* for federal, Minnesota and North Dakota income taxes.

Table of ContentsItem 2. Management's Discussion and Analysis of Financial Condition and Results of OperationsResults of Operations

Following is an analysis of the operating results of Otter Tail Corporation (the Company, we, us and our) by business segment for the three months ended March 31, 2018 and 2017 followed by a discussion of changes in our consolidated financial position during the three months ended March 31, 2018 and our business outlook for the remainder of 2018.

Comparison of the Three Months Ended March 31, 2018 and 2017

Consolidated operating revenues were \$241.3 million for the three months ended March 31, 2018 compared with \$214.1 million for the three months ended March 31, 2017. Operating income was \$37.6 million for the three months ended March 31, 2018 compared with \$34.2 million for the three months ended March 31, 2017. The Company recorded diluted earnings per share from continuing operations and in total of \$0.66 for the three months ended March 31, 2018 compared with \$0.49 for the three months ended March 31, 2017.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the three-month periods ended March 31, 2018 and 2017 will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

	March	March
Intersegment Eliminations (<i>in thousands</i>)	31,	31,
	2018	2017
Operating Revenues:		
Electric	\$ 15	\$ 8
Nonelectric	(1)	--
Costs of Products Sold	5	1
Other Nonelectric Expenses	9	7

Electric

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<i>(in thousands)</i>	Three Months Ended			%
	March 31, 2018	2017	Change	
Retail Sales Revenues from Contracts with Customers	\$ 109,180	\$ 106,454	\$ 2,726	2.6
Changes in Accrued Revenues under Alternative Revenue Programs	(875)	(1,239)	364	29.4
Total Retail Sales Revenue	\$ 108,305	\$ 105,215	\$ 3,090	2.9
Wholesale Revenues – Company Generation	1,015	867	148	17.1
Other Revenues	13,645	12,469	1,176	9.4
Total Operating Revenues	\$ 122,965	\$ 118,551	\$ 4,414	3.7
Production Fuel	18,706	16,382	2,324	14.2
Purchased Power – System Use	21,593	19,188	2,405	12.5
Other Operation and Maintenance Expenses	39,475	37,277	2,198	5.9
Depreciation and Amortization	13,922	13,066	856	6.6
Property Taxes	3,835	3,798	37	1.0
Operating Income	\$ 25,434	\$ 28,840	\$ (3,406)	(11.8)
Electric kilowatt-hour (kwh) Sales <i>(in thousands)</i>				
Retail kwh Sales	1,453,893	1,389,921	63,972	4.6
Wholesale kwh Sales – Company Generation	39,404	38,934	470	1.2
Heating Degree Days	3,591	3,082	509	16.5

The following table shows heating degree days as a percent of normal:

	Three Months ended March 31,	
	2018	2017
Heating Degree Days	106.6%	90.1%

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The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kwh sales under actual weather conditions and expected retail kwh sales under normal weather conditions in the first quarters of 2018 and 2017 and between the quarters:

	2018 vs Normal	2017 vs Normal	2018 vs 2017
Effect on Diluted Earnings Per Share	\$ 0.022	\$(0.023)	\$0.045

The \$3.1 million increase in retail revenue includes:

A \$4.0 million increase in retail revenue related to the recovery of increased fuel and purchased power costs due to an increase in kwhs generated to serve retail customers.

A \$2.7 million increase in revenues related to increased usage due to colder weather in the first quarter of 2018, evidenced by a 16.5% increase in heating degree days between the quarters.

A \$1.6 million net retail revenue increase related to an interim rate increase implemented in North Dakota in January 2018 in conjunction with the 2017 general rate increase request.

A \$0.7 million increase in North Dakota and Minnesota Renewable Resource Adjustment rider revenues.

A \$0.4 million increase in Conservation Improvement Program (CIP) cost recovery revenues.

offset by:

A \$2.8 million reduction in revenues mainly related to the implementation of final retail rates in Minnesota that were lower than interim rates in effect in the first quarter of 2017.

A \$2.4 million reduction in revenues for the provision of refunds related to the recovery of federal income taxes in current retail electric rates in Minnesota and South Dakota that are in excess of lower federal income taxes under the 2017 Tax Cuts and Jobs Act (TCJA).

A \$0.7 million decrease in North Dakota and South Dakota Environmental Cost Recovery rider revenues mainly due to the reduction in the federal income tax rate under the TCJA and adjustment of the return on equity component of the rider in North Dakota to the level requested in 2017 general rate case.

A \$0.4 million decrease in North Dakota Transmission Cost Recovery rider revenues in correlation with the North Dakota general rate case initiated in November 2017 and the reduction in the federal income tax rate under the TCJA.

Other electric revenues increased \$1.2 million due to an increase in Midcontinent Independent System Operator, Inc. (MISO) transmission tariff revenue resulting from increased transmission system investments and higher usage of company-owned transmission assets by others.

Production fuel costs increased \$2.3 million, mainly due to a 31.4% increase in kwhs generated from our fuel burning plants to provide electricity for the increase in retail and wholesale demand driven by the colder weather in our service territory in the first quarter of 2018.

The cost of purchased power to serve retail customers increased \$2.4 million due to a 14.2% increase in the cost per kwh purchased driven by higher market demand resulting from colder weather in the first quarter of 2018 compared with the first quarter of 2017.

Electric operating and maintenance expenses increased \$2.2 million due to:

A \$1.5 million increase in operating expenses resulting primarily from lower capitalized labor, increased vegetation management costs and higher rate case expenses.

A \$0.4 million increase in CIP expenditures.

A \$0.3 million increase in transmission service charges. Transmission charges were lower in the first quarter of 2017 due to a \$1.1 million MISO refund. The MISO refund related to a reduction in the return on equity component of the MISO tariff imposed from November 2013 through January 2015. This refund was offset by \$0.8 million in Southwest Power Pool transmission cost true-ups recorded in the first quarter of 2017.

Depreciation expense increased \$0.9 million mainly due to an increase in transmission project unitization and the Big Stone South-Brookings transmission line being placed in service in September 2017.

Table of ContentsManufacturing

	Three Months			
	Ended			
	March 31,		%	
<i>(in thousands)</i>	2018	2017	Change	Change
Operating Revenues	\$68,662	\$58,417	\$10,245	17.5
Cost of Products Sold	52,041	45,028	7,013	15.6
Operating Expenses	6,873	5,776	1,097	19.0
Depreciation and Amortization	3,854	3,857	(3)	(0.1)
Operating Income	\$5,894	\$3,756	\$2,138	56.9

The \$10.2 million increase in revenues in our Manufacturing segment includes the following:

Revenues at BTD Manufacturing, Inc. (BTD) increased \$9.6 million, including increases in parts sales of \$5.2 million to manufacturers of industrial and construction equipment, \$2.1 million to manufacturers of lawn and garden and agricultural equipment and \$1.8 million to manufacturers of recreational vehicles. Revenues from scrap metal sales increased \$0.5 million due to higher scrap volumes from increased production and a 12% increase in scrap metal pricing.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, improved \$0.7 million due to increased sales of horticultural containers across its customer base.

The \$7.0 million increase in cost of products sold in our Manufacturing segment includes the following:

Cost of products sold at BTD increased \$6.4 million in relationship to increased parts sales.

Cost of products sold at T.O. Plastics increased \$0.6 million related to the increase in product sales.

The \$1.1 million increase in operating expenses in our Manufacturing segment includes a \$1.0 million increase in expenses at BTD due to a \$0.5 million increase in incentives earned on higher sales and \$0.5 million in increased computer and software, contracted services and other administrative and general expenses. Operating expenses at T.O. Plastics increased \$0.1 million quarter over quarter.

Plastics

<i>(in thousands)</i>	Three Months Ended		Change	% Change
	2018	2017		
Operating Revenues	\$49,653	\$37,157	\$12,496	33.6
Cost of Products Sold	36,749	30,250	6,499	21.5
Operating Expenses	2,614	2,028	586	28.9
Depreciation and Amortization	951	923	28	3.0
Operating Income	\$9,339	\$3,956	\$5,383	136.1

Plastics segment revenues increased \$12.5 million due to a 20.7% increase in polyvinyl-chloride (PVC) pipe prices and a 10.7% increase in pounds of PVC pipe sold. The increase in revenue was partially offset by a \$6.5 million increase in cost of products sold due to the increase in sales volume and a 9.8% increase in costs per pound of pipe sold. The increase in pipe prices in excess of the increase in cost of products sold resulted in a \$6.0 million increase in gross margin on pipe sold. Plastics segment operating expenses increased by \$0.6 million due to an increase in incentives earned and commissions paid on higher sales.

Table of ContentsCorporate

Corporate includes items such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of operating segment performance. Corporate is not an operating segment. Rather it is added to operating segment totals to reconcile to totals on our consolidated statements of income.

<i>(in thousands)</i>	Three Months Ended		Change	%
	2018	2017		
Operating Expenses	\$3,016	\$2,338	\$ 678	29.0
Depreciation and Amortization	36	8	28	350.0

Corporate operating expenses increased \$0.7 million, mainly as a result of a \$0.3 million increase in professional services and dues expenses and a \$0.3 million increase in employee benefit costs.

Other Income

The \$0.6 million increase in other income in the three months ended March 31, 2018 compared with the three months ended March 31, 2017 is mostly due to \$0.5 million increase in the allowance for equity funds used during construction (AFUDC) in our Electric Segment resulting from an increase in construction work in progress subject to AFUDC.

Income Taxes – Continuing Operations

Income tax expense - continuing operations decreased \$2.6 million in the three months ended March 31, 2018 compared with the three months ended March 31, 2017 mainly due to the reduction in the federal income tax rate from 35% to 21% under the TCJA resulting in a \$3.6 million reduction in income tax expense. The decrease due to the federal income tax rate reduction was partially offset by \$1.1 million increase in income tax expense resulting from a \$4.1 million increase in income from continuing operations before income taxes. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income from continuing operations before income taxes and income tax expense for continuing operations reported on our consolidated statements of income for the three-month periods ended March 31, 2018 and 2017:

<i>(in thousands)</i>	Three Months	
	Ended March 31, 2018	2017
Income Before Income Taxes – Continuing Operations	\$30,009	\$25,892
Tax Computed at Company’s Net Composite Federal and State Statutory Rate (26% for first quarter 2018, 39% for first quarter 2017)	7,802	10,098
Increases (Decreases) in Tax from:		
Federal Production Tax Credits (PTCs)	(1,120)	(2,052)
Property Related Differences and Other Regulatory Adjustments	(1,073)	105
Excess Tax Deduction – Equity Method Stock Awards	(624)	(697)
Other Comprehensive Income Deferred Tax Rate Adjustment	(531)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(212)
Research and Development and Other Tax Credits	(180)	(157)
Allowance for Funds Used During Construction – Equity	(167)	(67)
Corporate Owned Life Insurance	(8)	(294)
Section 199 Domestic Production Activities Deduction	--	(330)
Other Items – Net	(47)	(31)
Income Tax Expense – Continuing Operations	\$3,794	\$6,363
Effective Income Tax Rate – Continuing Operations	12.6 %	24.6 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP’s kwh generation from its wind turbines eligible for PTCs decreased 49.3% in the three months ended March 31, 2018 compared with the three months ended March 31, 2017 due to the PTC eligibility period ending for one of OTP’s wind farms. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

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The following table presents the status of our lines of credit as of March 31, 2018 and December 31, 2017:

<i>(in thousands)</i>	Line Limit	In Use on March 31, 2018	Restricted due to Outstanding Letters of Credit	Available on March 31, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	\$ 130,000	\$ 6,182	\$ --	\$ 123,818	\$ 130,000
OTP Credit Agreement	170,000	24,137	300	145,563	57,239
Total	\$ 300,000	\$ 30,319	\$ 300	\$ 269,381	\$ 187,239

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if needed. Our balance sheet is strong and we are in compliance with our debt covenants. Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings and alternative financing arrangements such as leasing.

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 3, 2018 we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 3, 2021. On May 3, 2018, we also filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 common shares until May 3, 2021, under the Company's Automatic Dividend Reinvestment (DRIP) and Share Purchase Plan (the Plan), which permits shares purchased by participants in the Plan to be either new issue common shares or common shares purchased in the open market. On May 1, 2018 our Distribution Agreement with J.P. Morgan Securities (JPMS) ended as required under the agreement. This Distribution Agreement allowed us to offer and sell our common shares from time to time in an At-the-Market (ATM) offering program through JPMS, up to an aggregate sales price of \$75 million. We expect to establish a new ATM offering program to replace our prior program under which we may offer and sell our common shares from time to time under the shelf registration statement.

Equity or debt financing will be required in the period 2018 through 2022 given the expansion plans related to our Electric segment to fund construction of new rate base investments. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Our operating cash flows and access to capital markets can be

impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 7 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the board of directors. On February 5, 2018 our board of directors increased the quarterly dividend from \$0.32 to \$0.335 per common share.

Cash provided by operating activities of continuing operations was \$4.8 million for the three months ended March 31, 2018 compared with cash provided by operating activities of \$21.2 million for the three months ended March 31, 2017. Primary reasons for the \$16.4 million decrease in cash provided by continuing operations between the quarters were a \$20.0 million increase in discretionary contributions to the Company's funded pension plan, partially offset by a \$6.6 million increase in net income from continuing operations. A \$6.4 million increase in cash used for noncurrent liabilities and deferred credits was partially offset by a \$3.5 million reduction in cash used for working capital items between the quarters. The \$3.5 million decrease in cash used for working capital items between the quarters includes the following major items:

An \$11.4 million decrease in cash used for accounts payable in the Plastics segment related to a change in the timing of resin purchases and payments between the periods and an increase in resin purchases in the first quarter of 2018 compared with the first quarter of 2017 due to an increase in pipe production and sales between quarters.

offset by:

Increases in cash used for accounts receivable of \$7.1 million at BTD and \$1.9 million at the plastic pipe companies related to increased sales and product prices at the respective companies in the first quarter of 2018 compared with the first quarter of 2017.

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Net cash used in investing activities was \$23.8 million for the three months ended March 31, 2018 compared with \$30.0 million for the three months ended March 31, 2017. The \$6.2 million decrease in cash used for investing activities includes a \$6.5 million decrease in capital expenditures, mainly due to a \$7.2 million reduction in cash used for capital expenditures at OTP as the Big Stone South–Brookings 345 kiloVolt (kV) transmission line project, placed in service September 2017, was under construction during the first quarter of 2017. OTP work continues on the Big Stone South–Ellendale 345 kV transmission line project and on a major project to replace its customer information system.

Net cash provided by financing activities was \$4.1 million for the three months ended March 31, 2018 compared with \$8.8 million for the three months ended March 31, 2017. Financing activities in the first quarter of 2018 included proceeds from the issuance of \$100 million in privately placed 4.07% Senior Unsecured Notes due February 7, 2048, which were used to pay down a portion of borrowings then outstanding under the OTP Credit Agreement. Additional borrowings under our credit agreements were used to fund a portion of first quarter 2018 capital expenditures. Common dividend payments of \$13.3 million in the first quarter of 2018 contributed to the \$15.1 million reduction in cash and cash equivalents during the quarter.

Financing activities in the first quarter of 2017 included a net increase in short-term and long-term borrowings of \$13.2 million and an increase in checks issued in excess of cash of \$8.0 million, which has a direct relationship with the increase in cash used for accounts payable in the operating section of the cash flow statement, partially offset by \$12.6 million in common dividend payments.

CAPITAL REQUIREMENTS2018-2022 Capital Expenditures

The following table shows our 2017 capital expenditures and 2018 through 2022 anticipated capital expenditures and electric utility average rate base:

<i>(in millions)</i>	2017	2018	2019	2020	2021	2022	Total
Capital Expenditures:							
<u>Electric Segment:</u>							
Renewables and Natural Gas Generation		\$ 1	\$ 308	\$ 102	\$ 50	\$ 1	\$ 462
Transformative Technology and Infrastructure		--	22	32	43	39	136
Transmission		45	12	9	7	7	80
Other		49	40	42	45	47	223
Total Electric Segment	\$ 119	\$ 95	\$ 382	\$ 185	\$ 145	\$ 94	\$ 901
Manufacturing and Plastics Segments	14	15	14	15	14	14	72
Total Capital Expenditures	\$ 133	\$ 110	\$ 396	\$ 200	\$ 159	\$ 108	\$ 973

Total Electric Utility Average Rate Base \$1,055 \$1,091 \$1,297 \$1,480 \$1,568 \$1,625

The consolidated capital expenditure plan for the 2018-2022 time period calls for \$973 million based on the need for additional wind and solar in rate base and capital spending for Astoria Station, a natural gas-fired plant that is expected to replace Hoot Lake Plant when it is retired in 2021. Given the increased capital expenditure plan, our compounded annual growth rate in rate base is projected to be 9.0% from 2017 through 2022. Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2018 through 2022 timeframe.

On November 16, 2016 OTP entered into an Asset Purchase Agreement (the Purchase Agreement) with EDF Renewable Development, Inc. and certain of its affiliated companies (EDF) to purchase and assume the development assets associated with a 150-megawatt (MW) wind farm in southeastern North Dakota (the Merricourt Project) for a purchase price of \$34.7 million, subject to adjustments for interconnection costs. The Purchase Agreement is currently expected to close no earlier than mid-2018, pending regulatory reviews, satisfactory interconnection costs and other conditions. On the same day, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement with EDF that will be effective upon the closing of the Purchase Agreement pursuant to which EDF will construct the wind farm with a targeted completion date in 2019 for consideration of \$200.5 million, subject to certain adjustments, payable following the closing of the Purchase Agreement in installments in connection with certain project construction milestones. The agreements contain representations, warranties, covenants and indemnities customary to transactions of this type and include provisions for liquidated damages to be paid by EDF in the event of certain occurrences described in the agreements. As of March 31, 2018, OTP had capitalized approximately \$4.6 million in development costs associated with the Merricourt Project. A final order for an Advance Determination of Prudence (ADP), subject to qualifications and compliance obligations, and a Certificate of Public Convenience and Necessity were issued by the NDPSC on November 3, 2017. On October 26, 2017 the MPUC approved the facility under the Renewable Energy Standard making the Merricourt Project eligible for cost recovery under the Minnesota Renewable Resource Recovery rider.

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In addition to the Merricourt Project, OTP is moving forward with plans for the development, construction and ownership of a 250-MW simple-cycle natural gas-fired combustion turbine generation facility near Astoria, South Dakota (Astoria Station) as part of its plan to reliably meet customers' electric needs, replace expiring capacity purchase agreements and prepare for the planned retirement of its Hoot Lake Plant in 2021. OTP expects the project will cost approximately \$165 million. As of March 31, 2018, OTP had capitalized approximately \$5.4 million in development costs associated with Astoria Station. A final order granting ADP for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations.

If a resource addition is determined to be prudent by the NDPSC, a public utility may recover in its rates for North Dakota customers, and in a timely manner consistent with the public utility's financial obligations, the jurisdictional share of amounts the public utility reasonably incurred or obligated on a prudent resource addition, including accrued allowance for funds used during construction, even though the resource addition may never be fully operational or used by the public utility to serve its North Dakota customers. The cost amortization period for a discontinued resource addition may not exceed five years from the date commencement of the recovery is approved by the NDPSC. No return on amounts incurred or obligated by the public utility may be authorized for the period after the resource addition is discontinued.

Contractual Obligations

In the first quarter of 2018 OTP entered into an agreement to lease rail cars for transporting coal to Hoot Lake Plant. As a result, our operating lease obligations reported in the table on page 50 of our Annual Report on Form 10-K for the year ended December 31, 2017 increased \$0.2 million for 2018, \$0.6 million for 2019 and 2020, and \$0.1 million for 2021.

CAPITAL RESOURCES

On May 3, 2018 we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 3, 2021. On May 3, 2018 we also filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 common shares under our Automatic Dividend Reinvestment (DRIP) and Share Purchase Plan (the Plan), which permits shares purchased by participants in the Plan to be either new issue common shares or common shares purchased in the open market. The shelf registration for the DRIP expires on May 3, 2021. On May 1, 2018 our Distribution Agreement with JPMS ended. This Distribution Agreement allowed us to offer and sell our common shares from time to time in an ATM offering program through JPMS up to an aggregate sales price of \$75 million. We expect to establish a new At-the-Market offering program to replace our prior program under which we may offer and sell our common shares from time to under the shelf registration statement.

Short-Term Debt

The following table presents the status of our lines of credit as of March 31, 2018 and December 31, 2017:

<i>(in thousands)</i>	Line Limit	In Use on March 31, 2018	Restricted due to Outstanding Letters of Credit	Available on March 31, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	\$130,000	\$6,182	\$ --	\$123,818	\$130,000
OTP Credit Agreement	170,000	24,137	300	145,563	57,239
Total	\$300,000	\$30,319	\$ 300	\$269,381	\$187,239

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured \$130 million revolving credit facility that may be increased to \$250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 31, 2017 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of certain of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.50%, subject to adjustment based on our senior unsecured credit ratings or the issuer rating if a rating is not provided for the senior unsecured credit. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation (Varistar) and its subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial

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Covenants.” The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to \$40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured \$170 million revolving credit facility that may be increased to \$250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2017 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed \$50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP’s senior unsecured debt or the issuer rating if a rating is not provided for the senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial Covenants.” The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. OTP’s obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

2018 Note Purchase Agreement

On November 14, 2017, OTP entered into a Note Purchase Agreement (the 2018 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, \$100 million aggregate principal amount of OTP’s 4.07% Series 2018A Senior Unsecured Notes due February 7, 2048 (the 2018 Notes). The 2018 Notes were issued on February 7, 2018. Proceeds from the 2018 Notes were used to repay outstanding borrowings under the OTP Credit Agreement.

OTP may prepay all or any part of the 2018 Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2018 Note Purchase Agreement, any prepayment made by OTP of all of the 2018 Notes then outstanding on or after August 7, 2047 will be made without any make-whole amount. The 2018 Note Purchase Agreement also requires OTP to offer to prepay all outstanding 2018 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2018 Note Purchase Agreement) of OTP.

The 2018 Note Purchase Agreement contains a number of restrictions on the business of OTP. These include restrictions on OTP's abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2018 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2018 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2018 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2018 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the 2018 Notes than any analogous provision contained in the 2018 Note Purchase Agreement (an Additional Covenant), then unless waived by the Required Holders (as defined in the 2018 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2018 Note Purchase Agreement. The 2018 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

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2016 Note Purchase Agreement

On September 23, 2016 we entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which we agreed to issue to the purchasers, in a private placement transaction, \$80 million aggregate principal amount of our 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The 2026 Notes were issued on December 13, 2016. Our obligations under the 2016 Note Purchase Agreement and the 2026 Notes are guaranteed by our Material Subsidiaries (as defined in the 2016 Note Purchase Agreement, but specifically excluding OTP). The proceeds from the issuance of the 2026 Notes were used to repay the remaining \$52,330,000 of our 9.000% Senior Notes due December 15, 2016, and to pay down a portion of the \$50 million in funds borrowed in February 2016 under our Term Loan Agreement described below.

We may prepay all or any part of the 2026 Notes (in an amount not less than 10% of the aggregate principal amount of the 2026 Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2016 Note Purchase Agreement, any optional prepayment made by us of all of the 2026 Notes on or after September 15, 2026 will be made without any make-whole amount. We are required to offer to prepay all of the outstanding 2026 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2016 Note Purchase Agreement) of the Company. In addition, if we and our Material Subsidiaries sell a “substantial part” of our or their assets and use the proceeds to prepay or retire senior Interest-bearing Debt (as defined in the 2016 Note Purchase Agreement) of the Company and/or a Material Subsidiary in accordance with the terms of the 2016 Note Purchase Agreement, we are required to offer to prepay a Ratable Portion (as defined in the 2016 Note Purchase Agreement) of the 2026 Notes held by each holder of the 2026 Notes.

The 2016 Note Purchase Agreement contains a number of restrictions on the business of the Company and our Material Subsidiaries. These include restrictions on our and our Material Subsidiaries’ abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, engage in transactions with related parties, redeem or pay dividends on our and our Material Subsidiaries’ shares of capital stock, and make investments. The 2016 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading “Financial Covenants.” The 2016 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our or our Material Subsidiaries’ credit ratings.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, \$60 million aggregate principal amount of OTP’s 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and \$90 million aggregate principal amount of OTP’s 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The notes were issued on February 27, 2014.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2013 Note Purchase Agreement) of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an Additional Covenant), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

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2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued \$140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its \$122 million senior unsecured notes issued in three series consisting of \$30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; \$42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and \$50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement). On August 21, 2017 OTP used borrowings under the OTP Credit Agreement to retire its \$33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, which had been issued under the 2007 Note Purchase Agreement and matured on August 20, 2017.

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Financial Covenants

We were in compliance with the financial covenants in our debt agreements as of March 31, 2018.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

Our borrowing agreements are subject to certain financial covenants. Specifically:

Under the Otter Tail Corporation Credit Agreement and the 2016 Note Purchase Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and

Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis). As of March 31, 2018, our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement and the 2016 Note Purchase Agreement was 4.62 to 1.00.

Under the 2016 Note Purchase Agreement, we may not permit our Priority Indebtedness to exceed 10% of our Total Capitalization.

Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.

Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of March 31, 2018, OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.51 to 1.00.

Under the 2013 Note Purchase Agreement and the 2018 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, in each case as provided in the related agreement.

As of March 31, 2018, our ratio of Interest-bearing Debt to Total Capitalization was 0.47 to 1.00 on a consolidated basis and 0.48 to 1.00 for OTP. Neither Otter Tail Corporation nor OTP had any Priority Indebtedness outstanding as of March 31, 2018.

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We and our subsidiary companies have outstanding letters of credit totaling \$3.2 million, but our line of credit borrowing limits are only restricted by \$0.3 million in outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2018 BUSINESS OUTLOOK

We are raising our consolidated diluted earnings per share guidance for 2018 to be in the range of \$1.90 to \$2.05 from our previously announced guidance range of \$1.80 to \$1.95. The revised guidance is the result of stronger-than-expected first quarter results from our Plastics segment and reflects strategies for improving future operating results. We have taken into consideration the cyclical nature of some of our businesses as well as current regulatory factors and economic challenges facing our Electric, Manufacturing and Plastics segments. We expect capital expenditures for 2018 to be \$110 million compared with actual cash used for capital expenditures of \$133 million in 2017. Our planned expenditures for 2018 include \$33 million for the Big Stone South-Ellendale transmission line project, which positively impacts earnings by providing an immediate return on invested funds through rider recovery mechanisms.

Segment components of our 2018 earnings per share guidance range compared with 2017 actual earnings are as follows:

	2017	2018 Guidance		2018 Guidance	
	EPS by	February 12, 2018		May 7, 2018	
Diluted Earnings Per Share	Segment	Low	High	Low	High
Electric	\$ 1.24	\$ 1.34	\$ 1.37	\$ 1.34	\$ 1.37
Manufacturing	\$ 0.28	\$ 0.26	\$ 0.30	\$ 0.26	\$ 0.30
Plastics	\$ 0.54	\$ 0.36	\$ 0.40	\$ 0.48	\$ 0.52
Corporate	\$(0.25)	\$(0.16)	\$(0.12)	\$(0.18)	\$(0.14)
Total – Continuing Operations	\$ 1.81	\$ 1.80	\$ 1.95	\$ 1.90	\$ 2.05
Return on Equity	10.6%	10.1%	10.9%	10.6%	11.5%

Contributing to our revised earnings guidance for 2018 are the following items:

We expect 2018 Electric segment net income to be higher than 2017 segment net income based on:

- o Normal weather for the remainder of 2018. Milder than normal weather in 2017 negatively impacted diluted earnings per share by an estimated \$0.04 compared to normal.

- o Constructive outcome of the rate case filed in North Dakota on November 2, 2017, with a full year of increased interim rates in 2018. And constructive outcome of the rate cases filed in South Dakota on April 20, 2018. Our ability to obtain final rates similar to interim rates and reasonable rates of return depends on regulatory action under applicable statutes and regulations. We expect the effects of any reduction in interim or final rates due to lower tax rates in the new tax law to be offset by lower tax expenses. We cannot provide assurance our interim rates will become final.

- o Increases in transmission investments and other revenues.

offset by:

- o Increased operating and maintenance expenses of \$0.05 per share due to a planned maintenance outage at our Big Stone Plant and \$0.09 per share for increasing costs of pension, medical, workers compensation and retiree medical benefits. The increase in pension costs is a result of a decrease in the discount rate from 4.60% to 3.90%.

- o Higher depreciation and property tax expense due to large capital projects being put into service.

- o Increased interest expense related to replacing short-term debt at an average annual rate of 2.4% with long-term debt at a rate of 4.07% along with an increase in combined short-term and long-term borrowings to finance portions of 2018 planned capital expenditures.

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We expect 2018 net income from our Manufacturing segment to increase over 2017 based on the following:

- o An increase in earnings at BTD Manufacturing from an increase in year-over-year sales and planned improvement in operating margins through continued cost reductions.

- o An increase in earnings from T.O. Plastics mainly driven by year-over-year sales growth in our horticulture, life science and industrial markets.

- o Lower income taxes due to lower federal tax rates implemented as part of the new tax law.

- o Backlog for the manufacturing companies of approximately \$142 million for 2018 compared with \$105 million one year ago.

While we still expect 2018 net income from the Plastics segment to be lower than 2017, we are revising our earnings guidance for this segment upwards given strong first quarter results. Business conditions in the first quarter saw stronger than expected sales prices resulting in higher operating margins. While announced resin price increases are expected to lower operating margins through the remainder of the year, overall business conditions are expected to remain solid. Earnings in 2017 included an estimated impact of \$0.09 per diluted share due to market reaction to hurricanes in the Gulf of Mexico. Plastics segment net income for 2018 will be positively affected by lower federal tax rates in the new tax law.

Corporate costs, net of tax, are expected to be higher in 2018 than in 2017 when excluding the effect of revaluing deferred tax assets (\$0.18 per share) related to tax reform on 2017 net losses. The higher net-of-tax costs expected in 2018 are due, in part, to the lower tax rate in effect in 2018. The change in the guidance range for corporate costs is due to an additional increase in employee benefit costs due to the increase in our overall guidance range.

The impact of 2017 tax reform legislation on future results is based on reasonable estimates and is subject to adjustment on obtaining additional information or to reflect any future legislation, rules, regulations or interpretations of the tax reform legislation. We will continue to analyze and assess the effects of the 2017 tax law changes on our future business projections.

Critical Accounting Policies Involving Significant Estimates

The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires management to make

estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, interim rate refunds, warranty reserves and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the board of directors. A discussion of critical accounting policies is included under the caption "Critical Accounting Policies Involving Significant Estimates" on pages 57 through 59 of our Annual Report on Form 10-K for the year ended December 31, 2017. There were no material changes in critical accounting policies or estimates during the quarter ended March 31, 2018.

Forward Looking Information - Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

In connection with the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995 (the Act), we have filed cautionary statements identifying important factors that could cause our actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-Q and in future filings by the Company with the Securities and Exchange Commission, in our press releases and in oral statements, words such as "may", "will", "expect", "anticipate", "continue", "estimate", "project", "believes" or similar expressions are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act. These forward-looking statements involve risks and uncertainties. Actual results may differ materially from those contemplated by the forward-looking statements due to, among other factors, the risks and uncertainties described in the section entitled "Risk Factors" in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017, as well as the various factors described below:

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Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.

Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and increase borrowing costs and pension plan and postretirement health care expenses.

We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are unable to access capital at competitive rates, our ability to implement our business plans may be adversely affected.

Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of customers to finance purchases of goods and services, and our financial condition, as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.

We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

Any significant impairment of our goodwill would cause a decrease in our asset values and a reduction in our net operating income.

Declines in projected operating cash flows at BTD or the Plastics segment may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and debt covenants and pay dividends to our shareholders could have an adverse effect on us.

We rely on our information systems to conduct our business and failure to protect these systems against security breaches or cyber-attacks could adversely affect our business and results of operations. Additionally, if these systems fail or become unavailable for any significant period of time, our business could be harmed.

Economic conditions could negatively impact our businesses.

If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.

Our plans to grow and realign our business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.

We may, from time to time, sell assets to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any assets sold and other potential liabilities. The sale of any of our businesses could expose us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.

Significant warranty claims and remediation costs in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition.

We are subject to risks associated with energy markets.

Changes in tax laws, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could materially adversely affect our business, financial condition, results of operations and prospects.

Four of our operating companies have single customers that provide a significant portion of the individual operating company's and the business segment's revenue. The loss of, or significant reduction in revenue from, any one of these customers would have a significant negative financial impact on the operating company and its business segment and could have a significant negative financial impact on us.

We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to our shareholders or scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.

OTP's operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.

OTP's electric transmission and generation facilities could be vulnerable to cyber and physical attack that could impair its ability to provide electrical service to its customers or disrupt the U.S. bulk power system.

OTP's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

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Changes to regulation of generating plant emissions, including but not limited to carbon dioxide emissions, could affect our operating costs and the costs of supplying electricity to our customers.

Competition from foreign and domestic manufacturers, the price and availability of raw materials, prices and supply of scrap or recyclable material and general economic conditions could affect the revenues and earnings of our manufacturing businesses.

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for this segment.

We compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish the pipe companies' products from those of our competitors.

Changes in PVC resin prices can negatively affect our plastics business.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

At March 31, 2018 we had exposure to market risk associated with interest rates because we had \$6.2 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.50% under the Otter Tail Corporation Credit Agreement and OTP had \$24.1 million in short-term debt outstanding on March 31, 2018 subject to variable interest rates indexed to LIBOR plus 1.25% under the OTP Credit Agreement.

All of our remaining consolidated long-term debt outstanding on March 31, 2018 has fixed interest rates. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

The companies in our Manufacturing segment are exposed to market risk related to changes in commodity prices for steel, aluminum and polystyrene and other plastics resins. The price and availability of these raw materials could affect the revenues and earnings of our Manufacturing segment.

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, sales volume has been higher and when resin prices are falling, sales volume has been lower. Operating income may decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

Item 4. Controls and Procedures

Under the supervision and with the participation of company management, including our Chief Executive Officer and Chief Financial Officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of March 31, 2018, the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2018.

During the fiscal quarter ended March 31, 2018, there were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of ContentsPART II. OTHER INFORMATIONItem 1. Legal Proceedings

We are the subject of various pending or threatened legal actions and proceedings in the ordinary course of our business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. We record a liability in our consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where we have assessed that a loss is probable and an amount can be reasonably estimated. We believe the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

There has been no material change in the risk factors set forth under Part I, Item 1A, “Risk Factors” on pages 27 through 33 of our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

We do not have a publicly announced stock repurchase program. The following table shows common shares of the Company that were surrendered to us by employees to pay taxes in connection with shares issued for incentive awards in February 2018 under our 2014 Stock Incentive Plan:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
January 2018	--	--
February 2018	58,495	\$ 41.19

March 2018	--	--
Total	58,495	

Item 6. Exhibits

10.1 Form of 2018 Performance Award Agreement (Executives).*

10.2 Form of 2018 Performance Award Agreement (Legacy).*

31.1 Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101 Financial statements from the Quarterly Report on Form 10-Q of Otter Tail Corporation for the quarter ended March 31, 2018, formatted in Extensible Business Reporting Language: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Cash Flows and (v) the Condensed Notes to Consolidated Financial Statements.

*Management contract, compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.

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SIGNATURES

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.

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug

Kevin G. Moug
Chief Financial Officer and Senior Vice President
(Chief Financial Officer/Authorized Officer)

Dated: May 9, 2017