Section 1: 10-Q (FORM 10-Q)

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
[X] **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2019

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 incorporation or organization)	(I.R.S. Employer 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)

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

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares, par value $5.00 per share	OTTR	The Nasdaq Stock Market LLC

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 every Interactive Data File required to be submitted 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 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 ☐

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:

July 31, 2019 –39,755,277 Common Shares ($5 par value)

OTTER TAIL CORPORATION

INDEX

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands)	June 30, 2019	December 31, 2018
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 982	$ 861
Accounts Receivable:		
Trade—Net	105,407	75,144
Other	9,956	9,741
Inventories	105,860	106,270
Unbilled Receivables	18,349	23,626
Income Taxes Receivable	-	2,439
Regulatory Assets	14,501	17,225
Other	8,511	6,114
Total Current Assets	263,566	241,420
Investments	9,683	8,961
Other Assets	39,002	35,759
Goodwill	37,572	37,572
Other Intangibles—Net	11,858	12,450

Regulatory Assets		131,692		135,257
Right of Use Assets - Operating Leases		19,473		-
Plant				
Electric Plant in Service		2,170,259		2,019,721
Nonelectric Operations		234,245		228,120
Construction Work in Progress		73,069		181,626
Total Gross Plant		2,477,573		2,429,467
Less Accumulated Depreciation and Amortization		875,475		848,369
Net Plant		1,602,098		1,581,098
Total Assets	$	2,114,944	$	2,052,517

See accompanying condensed notes to consolidated financial statements.

Table of Contents

Otter Tail Corporation
Consolidated Balance Sheets
(not audited)

(in thousands, except share data)		**June 30, 2019**		**December 31, 2018**
LIABILITIES AND EQUITY				
Current Liabilities				
Short-Term Debt	$	36,602	$	18,599
Current Maturities of Long-Term Debt		177		172
Accounts Payable		111,848		96,291
Accrued Salaries and Wages		18,034		24,857
Accrued Federal and State Income Taxes		3,732		-
Other Accrued Taxes		11,753		17,287
Regulatory Liabilities		8,959		738
Current Operating Lease Liabilities		3,784		-
Other Accrued Liabilities		11,260		12,149
Total Current Liabilities		206,149		170,093
Pensions Benefit Liability		88,030		98,358
Other Postretirement Benefits Liability		73,080		71,561
Long-Term Operating Lease Liabilities		16,084		-
Other Noncurrent Liabilities		28,859		24,326
Commitments and Contingencies (note 9)				
Deferred Credits				
Deferred Income Taxes		122,035		120,976
Deferred Tax Credits		19,300		19,974
Regulatory Liabilities		224,655		226,469
Other		2,384		1,895
Total Deferred Credits		368,374		369,314
Capitalization				
Long-Term Debt—Net		590,063		590,002
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		-		-
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2019—39,754,902 Shares; 2018—39,664,884 Shares		198,775		198,324
Premium on Common Shares		345,030		344,250
Retained Earnings		205,115		190,433
Accumulated Other Comprehensive Loss		(4,615)		(4,144)
Total Common Equity		744,305		728,863
Total Capitalization		1,334,368		1,318,865
Total Liabilities and Equity	$	2,114,944	$	2,052,517

See accompanying condensed notes to consolidated financial statements.

Table of Contents

Otter Tail Corporation
Consolidated Statements of Income
(not audited)

(in thousands, except share and per-share amounts)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Operating Revenues				
Electric:				
Revenues from Contracts with Customers	$ 101,861	$ 105,284	$ 231,006	$ 229,109
Changes in Accrued Revenues under Alternative Revenue Programs	369	(1,565)	(680)	(2,440)
Total Electric Revenues	102,230	103,719	230,326	226,669
Product Sales under Contracts with Customers	126,973	122,629	244,849	240,945
Total Operating Revenues	229,203	226,348	475,175	467,614
Operating Expenses				
Production Fuel – Electric	8,296	15,888	27,216	34,594
Purchased Power – Electric System Use	19,633	14,402	41,585	35,995
Electric Operation and Maintenance Expenses	39,856	37,741	78,238	77,216
Cost of Products Sold (depreciation included below)	97,996	93,545	188,578	182,330
Other Nonelectric Expenses	13,262	12,649	26,739	25,143
Depreciation and Amortization	19,441	18,745	38,572	37,508
Property Taxes – Electric	3,900	3,273	7,859	7,108
Total Operating Expenses	202,384	196,243	408,787	399,894
Operating Income	26,819	30,105	66,388	67,720
Interest Charges	7,825	7,676	15,651	15,048
Nonservice Cost Components of Postretirement Benefits	1,075	1,386	2,110	2,803
Other Income	850	707	2,094	1,890
Income Before Income Taxes	18,769	21,750	50,721	51,759
Income Tax Expense	3,343	3,054	8,971	6,848
Net Income	15,426	18,696	41,750	44,911
Average Number of Common Shares Outstanding – Basic	39,712,036	39,605,717	39,684,679	39,578,296
Average Number of Common Shares Outstanding – Diluted	39,917,831	39,879,069	39,910,499	39,871,376
Basic Earnings Per Common Share	$ 0.39	$ 0.47	$ 1.05	$ 1.13
Diluted Earnings Per Common Share	$ 0.39	$ 0.47	$ 1.05	$ 1.13

See accompanying condensed notes to consolidated financial statements.

Table of Contents

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

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Net Income	$ 15,426	$ 18,696	$ 41,750	$ 44,911
Other Comprehensive Income (Loss):				
Unrealized Gain (Loss) on Available-for-Sale Securities:				
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	(4)	-	(4)	(110)
Unrealized Gains (Losses) Arising During Period	66	(13)	157	(79)
Income Tax (Expense) Benefit	(13)	3	(32)	40
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	49	(10)	121	(149)
Pension and Postretirement Benefit Plans:				
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 11)	129	233	259	460
Income Tax Expense	(33)	(61)	(67)	(120)
Adjustment to Income Tax Expense Related to 2017 Tax Cuts and Jobs Act	-	-	-	(531)
Pension and Postretirement Benefit Plans – net-of-tax	96	172	192	(191)
Total Other Comprehensive Income (Loss)	145	162	313	(340)
Total Comprehensive Income	$ 15,571	$ 18,858	$ 42,063	$ 44,571

See accompanying condensed notes to consolidated financial statements.

Table of Contents

Otter Tail Corporation
Consolidated Statements of Common Shareholders' Equity
For the Three- and Six-Month Periods Ended June 30, 2019 and 2018
(not audited)

(in thousands, except common shares outstanding)	Common Shares Outstanding	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
Balance, March 31, 2019	39,729,708	$ 198,649	$ 342,991	$ 203,619	$ (4,760)	$ 740,499
Common Stock Issuances, Net of Expenses	25,194	126	(109)			17
Net Income				15,426		15,426
Other Comprehensive Income					145	145
Employee Stock Incentive Plan Expense			2,148			2,148
Common Dividends ($0.35 per share)				(13,930)		(13,930)
Balance, June 30, 2019	39,754,902	$ 198,775	$ 345,030	$ 205,115	$ (4,615)	$ 744,305
Balance, March 31, 2018	39,626,594	$ 198,133	$ 341,841	$ 174,209	$ (6,133)	$ 708,050
Common Stock Issuances, Net of Expenses	25,778	129	(222)			(93)
Common Stock Retirements	(936)	(5)	(36)			(41)
Net Income				18,696		18,696
Other Comprehensive Loss					162	162
Employee Stock Incentive Plan Expense			1,107			1,107
Common Dividends ($0.335 per share)				(13,300)		(13,300)
Balance, June 30, 2018	39,651,436	$ 198,257	$ 342,690	$ 179,605	$ (5,971)	$ 714,581
Balance, December 31, 2018	39,664,884	$ 198,324	$ 344,250	$ 190,433	$ (4,144)	$ 728,863
Common Stock Issuances, Net of Expenses	145,242	727	(710)			17
Common Stock Retirements	(55,224)	(276)	(2,454)			(2,730)
Net Income				41,750		41,750
Other Comprehensive Income					313	313
ASU 2018-02 2017 TCJA Stranded Tax Transfer				784	(784)	-
Employee Stock Incentive Plan Expense			3,944			3,944
Common Dividends ($0.70 per share)				(27,852)		(27,852)
Balance, June 30, 2019	39,754,902	$ 198,775	$ 345,030	$ 205,115	$ (4,615)	$ 744,305
Balance, December 31, 2017	39,557,491	$ 197,787	$ 343,450	$ 161,286	$ (5,631)	$ 696,892
Common Stock Issuances, Net of Expenses	153,376	767	(860)			(93)
Common Stock Retirements	(59,431)	(297)	(2,153)			(2,450)
Net Income				44,911		44,911
Other Comprehensive Loss					(340)	(340)
Employee Stock Incentive Plan Expense			2,253			2,253
Common Dividends ($0.67 per share)				(26,592)		(26,592)
Balance, June 30, 2018	39,651,436	$ 198,257	$ 342,690	$ 179,605	$ (5,971)	$ 714,581

Table of Contents

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

(in thousands)	Six Months Ended June 30, 2019	2018
Cash Flows from Operating Activities		
Net Income	$ 41,750	$ 44,911
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	38,572	37,508
Deferred Tax Credits	(674)	(703)
Deferred Income Taxes	960	2,076
Change in Deferred Debits and Other Assets	3,884	10,309
Discretionary Contribution to Pension Plan	(10,000)	(20,000)
Change in Noncurrent Liabilities and Deferred Credits	11,942	(759)
Allowance for Equity/Other Funds Used During Construction	(688)	(1,060)
Stock Compensation Expense—Equity Awards	3,944	2,253
Other—Net	276	(193)
Cash (Used for) Provided by Current Assets and Current Liabilities:		
Change in Receivables	(30,478)	(25,677)
Change in Inventories	410	(2,401)
Change in Other Current Assets	2,870	2,428
Change in Payables and Other Current Liabilities	222	1,233

Change in Interest and Income Taxes Receivable/Payable	6,297	3,470
Net Cash Provided by Operating Activities	69,287	53,395
Cash Flows from Investing Activities		
Capital Expenditures	(54,012)	(49,094)
Net Proceeds from Disposal of Noncurrent Assets	3,405	1,477
Cash Used for Investments and Other Assets	(4,776)	(2,102)
Net Cash Used in Investing Activities	(55,383)	(49,719)
Cash Flows from Financing Activities		
Change in Checks Written in Excess of Cash	(1,120)	2,236
Net Short-Term Borrowings (Repayments)	18,003	(91,394)
Common Stock Issuance Expenses	-	(108)
Payments for Retirement of Capital Stock	(2,730)	(2,450)
Proceeds from Issuance of Long-Term Debt	-	100,000
Short-Term and Long-Term Debt Issuance Expenses	-	(441)
Payments for Retirement of Long-Term Debt	(84)	(107)
Dividends Paid	(27,852)	(26,592)
Net Cash Used in Financing Activities	(13,783)	(18,856)
Net Change in Cash and Cash Equivalents	121	(15,180)
Cash and Cash Equivalents at Beginning of Period	861	16,216
Cash and Cash Equivalents at End of Period	$ 982	$ 1,036

See accompanying condensed notes to consolidated financial statements.

Table of Contents

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, 2018. Because of seasonal and other factors, the earnings for the three- and six-months ended June 30, 2019 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, 2018.

1. Summary of Significant Accounting Policies

Revenue Recognition
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 customer’s specifications where the terms of the contract require transfer of the completed product. 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 Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606) (ASC 606), the Company also records adjustments to Electric segment revenues for amounts subject to future collection 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 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.

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 has recovered costs and earned 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 riders.
- In North Dakota: TCR, ECR, RRA and Generation Cost Recovery (GCR) 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 net of amounts billed that are subject to refund through future rider adjustments. Amounts accrued and subject to recovery through future rider rate updates and adjustments are reported as changes in accrued revenues under ARPs 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- and six-month periods ended June 30, 2019 and 2018.

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 customer 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. For revenue recognized on products when shipped, the operating companies have no further obligation to provide services related to such products. 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. 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 for a disaggregation of the Company's revenues by business segment for the three- and six-month periods ended June 30, 2019 and 2018.

Agreements Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases. 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.

Fair Value Measurements

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 June 30, 2019 and December 31, 2018:

June 30, 2019 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	$ 1,483		
Corporate Debt Securities – Held by Captive Insurance Company		$ 3,368	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		4,701	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	1,311		
Total Assets	$ 2,794	$ 8,069	

December 31, 2018 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	$ 1,294		
Corporate Debt Securities – Held by Captive Insurance Company		$ 5,898	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		1,586	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	838		
Total Assets	$ 2,132	$ 7,484	

The level 2 fair values for Government-Backed and Government-Sponsored Enterprises' and Corporate Debt Securities Held by the Company's Captive Insurance Company 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.

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 June 30, 2019 could be as high as $52.2 million, OTP's 35% share of unrecovered costs.

Inventories

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

(in thousands)	June 30, 2019	December 31, 2018
Finished Goods	$ 32,699	$ 37,130
Work in Process	19,414	20,393
Raw Material, Fuel and Supplies	53,747	48,747
Total Inventories	$ 105,860	$ 106,270

Goodwill and Other Intangible Assets

An assessment of the carrying amounts of goodwill of the Company's operating units as of December 31, 2018 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 six months of 2019:

(in thousands)	Gross Balance December 31, 2018	Accumulated Impairments	Balance (net of impairments) December 31, 2018	Adjustments to Goodwill in 2019	Balance (net of impairments) June 30, 2019
Manufacturing	$ 18,270	$ -	$ 18,270	$ -	$ 18,270
Plastics	19,302	-	19,302	-	19,302
Total	$ 37,572	$ -	$ 37,572	$ -	$ 37,572

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 June 30, 2019 and December 31, 2018:

June 30, 2019 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 10,693	$ 11,798	6 - 194
Other	154	94	60	14
Total	$ 22,645	$ 10,787	$ 11,858	

December 31, 2018 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 10,127	$ 12,364	12 - 200
Other	154	68	86	20
Total	$ 22,645	$ 10,195	$ 12,450	

The amortization expense for these intangible assets was:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Amortization Expense – Intangible Assets	$ 296	$ 345	$ 592	$ 690

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

(in thousands)	2019	2020	2021	2022	2023
Estimated Amortization Expense – Intangible Assets	$ 1,184	$ 1,133	$ 1,099	$ 1,099	$ 1,099

Supplemental Disclosures of Cash Flow Information

(in thousands)	As of June 30, 2019	2018
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$ 16,841	$ 11,564

New Accounting Standards Adopted

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 supersedes the requirements under ASC Topic 840 on leases and requires the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. 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. The Company adopted the amendments in ASU 2016-02 to its consolidated financial statements effective January 1, 2019. See note 8 for further information on leases and the Company's elections for applying the new standard.

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/(loss) (AOCI/(L)) to retained earnings for the stranded tax effects resulting from the Tax Cuts and Jobs Act (TCJA). Consequently, the amendments eliminate the stranded tax effects resulting from the 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. 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 adopted the updates in ASU 2018-02 effective January 1, 2019, applying them in the period of adoption and not retrospectively. On adoption, the Company reclassified $784,000 of income tax effects of the TCJA on the gross deferred tax amounts reflected in AOCI/(L) at the date of enactment of the TCJA from AOCI/(L) to retained earnings so the remaining gross deferred tax amounts related to items in AOCI/(L) will reflect current effective tax rates.

Support for the determination of the stranded tax effects resulting from the enactment of the TCJA in AOCI/(L) is provided in the table below.

(in thousands)	Unrealized Gains on Available-for-Sale Securities	Unamortized Actuarial Losses and Prior Service Costs on Pension and Other Postretirement Benefits	AOCI/(L)
Balance on December 22, 2017 – Pre-tax	$ 71	$ (5,672)	$ (5,601)
Effect of TCJA 14% Federal Tax Rate Reduction on Gross Deferred Tax Amounts	$ 10	$ (794)	$ (784)

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.

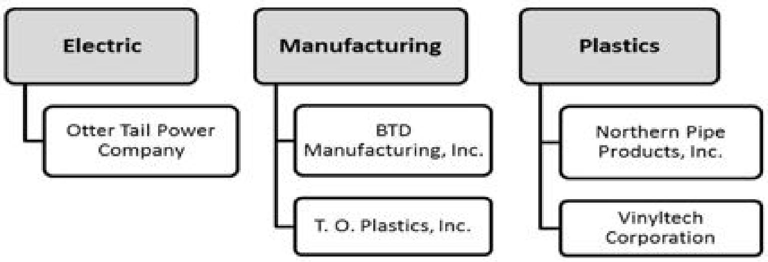
The amendments in ASU 2017-04 modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. An entity no longer will determine goodwill 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. The Company early adopted the amendments in ASU 2017-04 in the first quarter of 2019. The Company had no indication that any of its goodwill was impaired, therefore, the adoption of the updated standard had no impact on the Company's consolidated financial statements.

New Accounting Standards Pending Adoption

ASU 2016-13—In June 2016 the FASB issued ASU No. 2016-13, Financial Instruments—Credit Losses (Topic 326) (ASC Topic 326), which changes how entities account for credit losses on receivables and certain other assets. The guidance requires use of a current expected loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASC Topic 326 is effective for interim and annual periods beginning on or after December 15, 2019. The Company is currently evaluating what impact adoption of the new standard may have on its consolidated financial statements.

2. 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 maker. 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.



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, material handling components and extruded raw material stock. 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. 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.

While no single customer accounted for over 10% of the Company's consolidated revenue in 2018, certain customers provided a significant portion of each business segment's 2018 revenue. The Electric segment has one customer that provided 11.2% of 2018 segment revenues. The Manufacturing segment has one customer that manufactures and sells recreational vehicles that provided 22.2% of 2018 segment revenues and one customer that manufactures and sells lawn and garden equipment that provided 11.2% of 2018 segment revenues. The Manufacturing segment's top five revenue-generating customers provided over 52% of 2018 segment revenues. The Plastics segment has two customers that together provided 39.1% of 2018 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 sales within the United States accounted for 98.5% and 98.2% of operating revenues for the respective three-month periods ended June 30, 2019 and 2018, and 98.8% and 98.3% of operating revenues for the respective six-month periods ended June 30, 2019 and 2018.

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- and six-month periods ended June 30, 2019 and 2018 and total assets by business segment as of June 30, 2019 and December 31, 2018 are presented in the following tables:

Operating Revenue

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Electric Segment:				
Retail Sales Revenue from Contracts with Customers	$ 87,976	$ 89,400	$ 202,931	$ 198,580
Changes in Accrued ARP Revenues	369	(1,565)	(680)	(2,440)
Total Retail Sales Revenue	88,345	87,835	202,251	196,140
Transmission Services Revenue	11,469	11,313	22,331	23,216
Wholesale Revenues – Company Generation	941	2,539	2,468	3,554
Other Revenues	1,489	2,038	3,303	3,780
Total Electric Segment Revenues	102,244	103,725	230,353	226,690
Manufacturing Segment:				
Metal Parts and Tooling	62,541	57,388	129,265	114,315
Plastic Products and Tooling	9,353	7,961	18,398	18,196
Other	1,602	2,805	3,655	4,305
Total Manufacturing Segment Revenues	73,496	68,154	151,318	136,816
Plastics Segment – Sale of PVC Pipe Products	53,476	54,476	93,534	104,129
Intersegment Eliminations	(13)	(7)	(30)	(21)
Total	$ 229,203	$ 226,348	$ 475,175	$ 467,614

Interest Charges

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Electric	$ 6,625	$ 6,687	$ 13,266	$ 13,077
Manufacturing	646	555	1,230	1,109
Plastics	215	160	364	310
Corporate and Intersegment Eliminations	339	274	791	552
Total	$ 7,825	$ 7,676	$ 15,651	$ 15,048

Income Taxes

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Electric	$ 1,037	$ 611	$ 5,808	$ 2,709
Manufacturing	1,149	1,018	2,603	2,241
Plastics	2,044	2,207	3,373	4,621
Corporate	(887)	(782)	(2,813)	(2,723)
Total	$ 3,343	$ 3,054	$ 8,971	$ 6,848

Net Income (Loss)

(in thousands)	Three Months Ended June 30, 2019	2018	Six Months Ended June 30, 2019	2018
Electric	$ 7,502	$ 10,600	$ 26,202	$ 27,268
Manufacturing	3,990	3,583	8,832	7,747
Plastics	5,792	6,229	9,521	13,073
Corporate	(1,858)	(1,716)	(2,805)	(3,177)
Total	$ 15,426	$ 18,696	$ 41,750	$ 44,911

Identifiable Assets

(in thousands)	June 30, 2019	December 31, 2018
Electric	$ 1,752,432	$ 1,728,534
Manufacturing	211,374	187,556
Plastics	104,762	91,630
Corporate	46,376	44,797
Total	$ 2,114,944	$ 2,052,517

3. Rate and Regulatory Matters

Below are descriptions of OTP’s major capital expenditure projects that have had, or are expected to 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 2019 and 2018.

Major Capital Expenditure Projects

Astoria Station—OTP is constructing this 245-megawatt (MW) simple-cycle natural gas-fired combustion turbine generation facility near Astoria, South Dakota 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. A final order granting an Advance Determination of Prudence (ADP) for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations. On August 3, 2018 the SDPUC issued an order granting a site permit for Astoria Station. In a September 26, 2018 hearing the NDPSC established a GCR rider for future recovery of costs incurred for Astoria Station. On March 6, 2019 the SDPUC issued an order approving a settlement that allows a phase-in rider which includes recovery of Astoria Station costs. The interconnection agreement for Astoria Station was executed by MISO in December 2018 and accepted by the FERC in January 2019. Site preparation and excavating began in May 2019. As of June 30, 2019, OTP had capitalized approximately $19.6 million in project costs and allowance for funds used during construction (AFUDC) associated with Astoria Station. OTP expects the project will cost approximately $158 million.

Merricourt Wind Energy Center (Merricourt)—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 (collectively, EDF) to purchase and assume the development assets and certain specified liabilities associated with Merricourt, a 150-MW wind farm in southeastern North Dakota, for a purchase price of approximately $34.7 million, subject to adjustments for interconnection costs. Also on November 16, 2016, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement (the TEPC Agreement) with EDF-RE US Development, LLC (EDF-USD) pursuant to which EDF-USD will develop, design, procure, construct, interconnect, test and commission the wind farm for consideration of approximately $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 customary representations, warranties, covenants and indemnities for this type of transaction. On October 26, 2017 the MPUC approved the facility under the Renewable Energy Standard making Merricourt eligible for cost recovery under the Minnesota Renewable Resource Recovery rider, subject to qualifications and reporting obligations. The MPUC’s final written order was issued on January 10, 2018. A final order for an ADP, subject to qualifications and compliance obligations, and a Certificate of Public Convenience and Necessity were issued by the NDPSC on November 3, 2017. The phase-in rider approved by order of the SDPUC on March 6, 2019 includes recovery of Merricourt costs. The Merricourt generator interconnection agreement with MISO was approved by the FERC in April 2019.

In connection with action by the FERC, OTP and EDF agreed, in the First Amendment to the Purchase Agreement and the TEPC Agreement dated June 11, 2019, to change the purchase price to $37.7 million and to make a related reallocation of responsibility for interconnection costs and liabilities. On July 16, 2019, OTP closed on the purchase of substantially all of the development assets and assumed certain specified liabilities from EDF related to Merricourt pursuant to the Purchase Agreement, as amended, for a purchase price of approximately $37.7 million, subject to certain adjustments, and issued the notice to EDF-USD to begin construction in August 2019. As of June 30, 2019, OTP had capitalized approximately $5.6 million in development costs and AFUDC associated with Merricourt. OTP expects the project will cost approximately $270 million.

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This 345-kilovolt transmission line, energized on February 6, 2019, extends 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., and the parties have equal ownership interest in the transmission line portion of the project. The 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 MISO 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. OTP’s capitalized costs on this project as of June 30, 2019 were approximately $106 million, which includes assets that are 100% owned by OTP.

Recovery of OTP’s major transmission investments is through the MISO Tariff and Minnesota, North Dakota and South Dakota base rates and 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 is 8.61% and its allowed rate of return on equity (ROE) is 10.74%.

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 (see discussion under Minnesota Transmission Cost Recovery Rider below), and (2) approval of OTP’s proposal to transition rate base, expenses and revenues from ECR and TCR riders to base rate recovery, which occurred when final rates were implemented on November 1, 2017. Certain MISO expenses and revenues remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

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 changes to the MNCIP financial incentive. The model included incentives for utilities 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 was also limited to 40% of 2017 MNCIP spending and 35% of 2018 spending and will be limited to 30% of 2019 spending. The new model reduces the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism. The Minnesota Department of Commerce (MNDOC) issued a decision on May 20, 2019 to extend all utilities 2017-2019 CIP plans one year, through 2020.

On April 1, 2019 OTP filed a request for approval of its 2018 energy savings, recovery of $3.0 million in accrued financial incentives and recovery of 2018 program costs not included in base rates. On May 31, 2019 the MNDOC staff filed its comments with the MPUC on OTP’s 2018 petition to update its MNCIP rider, recommending the MPUC approve OTP’s petition with modifications. On June 24, 2019 OTP filed reply comments to the MNDOC staff recommendation reaffirming the $3.0 million request and offered an alternative $4.0 million financial incentive for the MPUC to consider.

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 MVPs 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 diverted 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 resulted in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision would 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 general rate case 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 June 11, 2018 the Minnesota Court of Appeals reversed the MPUC's order related to the inclusion of Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVPs and all revenues received from other utilities under MISO's tariffed rates as a credit in OTP Minnesota TCR revenue requirement calculations. On July 11, 2018 the MPUC filed a petition for review of the MVP decision to the Minnesota Supreme Court, which granted review of the Minnesota Court of Appeals decision. Oral arguments were heard by the Minnesota Supreme Court on March 11, 2019.

On November 30, 2018 OTP filed its annual update and supplemental filing to the Minnesota TCR rider. In this filing two scenarios were submitted based on whether the Minnesota Supreme Court affirms the original decision by the Minnesota Court of Appeals to exclude the MVP projects from the TCR rider or overturns the Minnesota Court of Appeals decision and includes the two MVP projects in the TCR rider. Action by the Minnesota Supreme Court is expected later in 2019. In addition, on April 1, 2019, the MNDOC filed comments in OTP's TCR rider docket, opposing OTP's proposal for TCR rider recovery of these costs. The MPUC is not expected to act on the TCR rider until after the Minnesota Supreme Court has acted and additional briefing has occurred in the docket. The estimated amount credited to Minnesota customers through the TCR rider through June 30, 2019 is approximately $2.9 million.

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. Accordingly, in its 2018 annual update filing OTP requested, and the MPUC approved, setting the Minnesota ECR rider rate to zero effective December 1, 2018. The remaining under-recovered balance was charged on customer billings in March and April 2019.

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. On June 21, 2019 OTP filed a request for approval of its annual update to the Minnesota RRA. This update requests recovery of the difference in PTCs in base rates and the actual PTCs generated, as well as recovery of Merricourt.

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 requested $13.1 million increase was net of reductions in North Dakota RRA, TCR and ECR rider revenues that would have resulted from a lower allowed rate of ROE 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 ROE of 10.3%. 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. 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 included $4.8 million related to tax reform and $1.2 million related to other updates.

In a September 26, 2018 hearing, the NDPSC approved an overall annual revenue increase of $4.6 million (3.1%) and a ROE of 9.77% on a 52.5% equity capital structure. This compares with OTP's March 2018 adjusted annual revenue increase request of $7.1 million (4.8%) and a requested ROE of 10.3%. The NDPSC's approval does not require any rate base adjustments from OTP's original request and establishes a GCR rider for future recovery of costs incurred for Astoria Station. The net revenue increase reflects a reduction in income tax recovery requirements related to the TCJA and decreases in rider revenue recovery requirements. Final rates were effective February 1, 2019, with refunds of excess revenues collected under interim rates applied to customers' April 2019 bills.

Renewable Resource Adjustment—OTP has a North Dakota RRA 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.

Effective in February 2019 with the implementation of general rates based on the results of OTP’s 2017 general rate case, recovery of renewable resource costs previously being recovered through the North Dakota RRA rider transitioned to recovery in base rates.

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. Based on the order in the 2017 general rate case, only certain costs will remain subject to refund or recovery through this rider: Southwest Power Pool (SPP) costs and MISO Schedule 26 and 26A revenues and expenses and costs related to rider projects still under construction in the test year used in the 2017 general rate case. This rider will continue to be updated annually for new or modified electric transmission facilities and associated operating costs.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota. The ECR rider has provided for a return on investment at the level approved in OTP’s preceding general rate case and for recovery of OTP’s North Dakota share of environmental investments and costs approved for recovery under the rider. Prior to its 2017 general rate case reaching a final settlement and final rates going into effect on February 1, 2019, OTP’s North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects were being recovered through the ECR rider. Effective February 1, 2019 these rate base investments are being recovered under general rates and the rider was zeroed out except for an overcollection balance that will be refunded to ratepayers.

Generation Cost Recovery Rider—On March 1, 2019 OTP filed a request with the NDPSC to establish an initial GCR rider rate for recovery of OTP’s North Dakota jurisdictional share of the revenue requirements of its investment in Astoria Station. This request was approved by the NDPSC on May 15, 2019. The new rate of 2.547% will be effective on bills rendered after July 1, 2019.

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. Interim rates went into effect October 18, 2018. The second step in the request was an additional 1.7% revenue increase to recover costs for Merricourt when the wind generation facility goes into service.

The SDPUC approved a partial settlement on March 1, 2019 on all issues of the rate case except ROE. The settlement includes approval of a phase-in plan to provide for a return on amounts invested in Astoria Station and Merricourt, which addresses the second step of the request for increased rates in South Dakota. The partial settlement also includes a moratorium on filing another general rate case in South Dakota until the new generation projects have been in service for a year. The settlement also allows OTP to retain the impact of lower tax rates related to the TCJA from January 1, 2018 through October 17, 2018 resulting in the reversal of an accrued refund liability and recognition of $1.0 million in revenue in the first quarter of 2019. The SDPUC approved the ROE portion of the rate case on May 14, 2019. Pursuant to the May 30, 2019 order, OTP’s allowed ROE was set at 8.75%, resulting in an annual revenue increase of approximately $2.2 million prior to the approval of a June 28, 2019 stipulation agreement discussed below. Final rates went into effect August 1, 2019. An interim rate refund for the lower ROE going back to October 18, 2018 will be applied to South Dakota customers’ October 2019 bills.

On June 28, 2019 OTP entered into a stipulation agreement with SDPUC staff for the purpose of correcting a mistake in OTP’s rate base in its 2018 general rate case docket. The revenue requirement stated in the SDPUC’s final order dated May 30, 2019 understated the correct amount of OTP's electric transmission plant in service by approximately $44 million. For South Dakota ratemaking purposes, the understatement results in an annual revenue requirement shortfall of approximately $341,000. To address the shortfall, the parties agreed that OTP would file an update to its South Dakota TCR rider. OTP will be authorized full recovery of the transmission rate base correction reflected in the TCR rider tracker beginning as of the first date of interim rates, October 18, 2018, with the TCR rider rate update to go into effect on October 1, 2019, all subject to SDPUC approval. The stipulation agreement had the effect of increasing the non-fuel annual revenue increase in the general rate case to approximately $2.6 million or 7.7%, which is 69% of the adjusted requested annual revenue increase of approximately $3.7 million or 11.1%, To ensure rates are appropriately set under the stipulation, the parties agreed to establish an earnings sharing mechanism to share with customers any weather-normalized earnings above the authorized ROE of 8.75%. OTP's annual weather-normalized earnings are reported each year by June 1 in its jurisdictional annual report, which will be used to determine the earnings level for purposes of calculating any refund. The earnings sharing mechanism requires that in the event OTP’s annual weather-normalized earnings exceed the SDPUC’s authorized ROE during any year until the ROE is reset in OTP's next general rate case, OTP will refund to customers 50% of any weather-normalized revenue that corresponds to the earnings in excess of its authorized ROE, up to a maximum of 9.50% ROE for a particular year. OTP will refund 100% of any earnings above 9.50% each year. In the event a refund is due under this provision, OTP will notify the SDPUC of the refund amount and plan for crediting customers within 30 days of filing its South Dakota jurisdictional annual report.

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. OTP has a TCR rider in South Dakota. A supplemental filing to update the rider was made on January 29, 2018 to reflect updated costs and collections and incorporate the impact of the reduction in the federal corporate income tax rate under the TCJA. Effective October 18, 2018, with the implementation of interim rates under South Dakota general rate case proceedings, the TCR rate was decreased as a result of recovery of certain costs being shifted to recovery in interim rates and proposed for ongoing recoveries in final base rates at the end of the 2018 general rate case.

OTP made a supplemental filing for the South Dakota TCR rider on February 1, 2019. On February 20, 2019 the SDPUC approved the supplemental filing and rates effective March 1, 2019. Two new projects were approved for recovery under the rider: The Lake Norden area transmission upgrade project with a recovery date effective January 1, 2019 and The Big Stone South – Ellendale project with a recovery date effective January 2020.

Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota. 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 South Dakota share of environmental investments and costs approved for recovery under the rider. Prior to interim rates going into effect on October 18, 2018 pending a final decision on OTP’s South Dakota general rate increase request, OTP’s South Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxics Standards projects were being recovered through the ECR rider. With the initiation of interim rates, recovery of the costs previously being recovered under the ECR rider was transitioned to recovery under interim rates and the South Dakota ECR rider rate was reset to provide a refund to customers while interim rates are in effect.

Phase-In Rider

On May 31, 2019 OTP petitioned the SDPUC for approval of its initial rate for the Phase-In Rate Plan Rider under the SDPUC’s authority granted in South Dakota. This rider filing is described in the most recent South Dakota general rate case settlement stipulation and approved by the SDPUC’s order in that rate case. The petition is OTP’s initial filing for the rider to recover actual and forecasted costs for Astoria Station and Merricourt, and forecasted net benefits associated with additional load growth in the Lake Norden area in OTP’s South Dakota jurisdiction.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
Rate Rider *(in thousands)*	2019	2018	2019	2018
Minnesota				
Conservation Improvement Program Costs and Incentives[1]	$ 2,618	$ 2,368	$ 4,770	$ 4,884
Renewable Resource Recovery	1,317	659	2,633	1,184
Transmission Cost Recovery	(56)	(458)	585	(487)
Environmental Cost Recovery	-	(18)	(1)	(49)
North Dakota				
Transmission Cost Recovery	874	1,165	2,646	3,227
Renewable Resource Adjustment	(93)	2,079	636	4,046
Environmental Cost Recovery	(12)	1,830	563	3,651
Generation Cost Recovery	222	-	470	-
South Dakota				
Transmission Cost Recovery	371	250	844	786
Conservation Improvement Program Costs and Incentives	96	122	340	351
Environmental Cost Recovery	(23)	515	(27)	1,035
Total	$ 5,314	$ 8,512	$ 13,459	$ 18,628

[1]*Includes MNCIP costs recovered in base rates.*

Table of Contents

Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2017 for the rate riders described above:

Rate Rider	R - Request Date A - Approval Date	Effective Date Requested or Approved		Annual Revenue *($000s)*	Rate
Minnesota					
Conservation Improvement Program					
2018 Incentive and Cost Recovery	R – April 1, 2019	October 1, 2019	$	11,926	$0.00710/kwh
2017 Incentive and Cost Recovery	A – October 4, 2018	November 1, 2018	$	10,283	$0.00600/kwh
2016 Incentive and Cost Recovery	A – September 15, 2017	October 1, 2017	$	9,868	$0.00536/kwh
Transmission Cost Recovery					
2018 Annual Update–Scenario A	R – November 30, 2018	June 1, 2019	$	6,475	Various
–Scenario B			$	2,708	Various
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$	(3,311)	Various
Environmental Cost Recovery					
2018 Annual Update	A – November 29, 2018	December 1, 2018	$	-	0% of base
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$	(1,943)	-0.935% of base
Renewable Resource Adjustment					
2019 Annual Update	R – June 21, 2019	November 1, 2019	$	12,571	$0.00469/kwh
2018 Annual Update	A – August 29, 2018	November 1, 2018	$	5,886	$0.00219/kwh
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$	1,279	$0.00049/kwh
North Dakota					
Renewable Resource Adjustment					
2019 Annual Update	A – May 1, 2019	June 1, 2019	$	(235)	-0.224% of base
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
Transmission Cost Recovery					
2018 Supplemental Update	A – December 6, 2018	February 1, 2019	$	4,801	Various
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
Environmental Cost Recovery					
2018 Update	A – December 19, 2018	February 1, 2019	$	(378)	-0.310% of base
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
Generation Cost Recovery					
2019 Initial Request	A – May 15, 2019	July 1, 2019	$	2,720	2.547% of base
South Dakota					
Transmission Cost Recovery					
2019 Rate Reset	R – July 31, 2019	October 1, 2019	$	2,050	Various
2019 Annual Update	A – February 20, 2019	March 1, 2019	$	1,638	Various
2018 Interim Rate Reset	A – October 18, 2018	October 18, 2018	$	1,171	Various
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
Environmental Cost Recovery					
	A				

2018 Interim Rate Reset	–	October 18, 2018	October 18, 2018	$ (189)	-$0.00075/kwh
2017 Annual Update	A –	October 13, 2017	November 1, 2017	$ 2,082	$0.00483/kwh
Phase-In Rate Plan					
2019 Initial Request	R –	May 31, 2019	September 1, 2019	$ 1,027	3.942% of base

TCJA

The TCJA, passed in December 2017, reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. At the time of passage, OTP’s electric rates had been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC each initiated dockets or proceedings to begin working with utilities to assess the impact of the lower rates on electric rates, and to develop regulatory strategies to incorporate the tax reduction into future electric rates, if warranted.

The MPUC required regulated utilities providing service in Minnesota to make filings by February 15, 2018. On August 9, 2018 the MPUC determined the impacts of the TCJA as calculated, including amortization of excess accumulated deferred income taxes, should be refunded and rates should be adjusted going forward to account for the impacts of the TCJA. On December 5, 2018 the MPUC issued its final order related to the TCJA docket directing OTP to return to ratepayers, in a one-time refund, the TCJA-related savings accrued prior to the refund effective date. OTP must amortize its protected excess accumulated deferred income taxes (ADIT) as early as U.S. Internal Revenue Service provisions allow and amortize its unprotected excess ADIT over ten years. OTP was instructed to use its 2017 year-end ADIT balance to calculate its excess ADIT balance. The order also directs OTP to use these savings to reduce customers' base rates prospectively—allocating the savings to customers in proportion to the size of each customer's bill, or to each customer class in proportion to the class's size. New rates reflecting the reduction in revenue requirements related to the TCJA tax rate reduction went into effect June 1, 2019. As of June 30, 2019, the accrued refund liability related to the tax rate reduction was $11.5 million for Minnesota customers. A one-time refund to Minnesota customers of $11.5 million in excess amounts billed from January 2018 through May 2019 will occur in August 2019.

As described above, OTP's recent general rate cases in North Dakota and South Dakota reflected the impact of the TCJA in interim rates. OTP accrued refund liabilities for the time periods during which revenues were collected under rates set to recover higher levels of federal income taxes than OTP incurred under the lower federal tax rates in the TCJA. The North Dakota liability of $0.8 million as of March 31, 2019 for amounts collected reflecting the higher tax rates under interim rates in effect in January and February 2018 was refunded with the interim rate refund in April 2019.

As of June 30, 2019, accrued refund liabilities related to the tax rate reduction were $0.2 million for FERC jurisdictional rates. As of March 15, 2018, the FERC granted the request for waiver from a group of MISO transmission operators (including OTP) to revise inputs to their projected net revenue requirements for the 2018 rate year to reflect recent tax law changes.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935 (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 suspension period, subject to ultimate approval by the FERC.

MVPs—MVPs are designed to enable the MISO 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%. Several 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 went to 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, 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 June 30, 2019.

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 U.S. 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. The motion is currently pending before the FERC.

On October 16, 2018 the FERC issued an order proposing a methodology for addressing the issues that were remanded to the FERC by the D.C. Circuit in April 2017. The FERC order established a paper hearing on how the methodology should apply to the proceedings pending before the FERC involving NETOs' ROE. In the order, the FERC selected a preliminary just and reasonable ROE for NETOs of 10.41%, exclusive of incentives, with a proposed cap on any pre-existing incentive-based total ROE at 13.08% and directed participants to submit supplemental briefs and additional written evidence regarding the proposed approaches to the Federal Power Act Section 206 inquiry and how to apply them to the NETO ROE complaints. On November 15, 2018, FERC issued an order establishing a paper hearing on whether and how a two-step ROE methodology developed for NETOs should apply to the ROE for MISO transmission owners. Initial briefs were due February 13, 2019 and reply briefs were due April 10, 2019. FERC is under no statutory timeline to act; however, the Company expects FERC to issue an order in the third or fourth quarter of 2019.

OTP believes its estimated accrued MISO Tariff ROE refund liability of $1.6 million as of June 30, 2019 related to the second MISO tariff ROE complaint is appropriate.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with 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 or conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

	June 30, 2019			Remaining Recovery/ Refund Period
(in thousands)	Current	Long-Term	Total	(months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$ 6,355	$ 115,246	$ 121,601	see below
Accumulated ARO Accretion/Depreciation Adjustment[1]	-	7,436	7,436	asset lives
Conservation Improvement Program Costs and Incentives[2]	1,861	4,659	6,520	27
Minnesota Transmission Cost Recovery Rider Accrued Revenues[2]	2,637	-	2,637	12
Deferred Marked-to-Market Losses[1]	1,202	372	1,574	18
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery[1]	-	1,359	1,359	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	698	590	1,288	22
Debt Reacquisition Premiums[1]	203	649	852	159
Deferred Income Taxes[1]	-	701	701	asset lives
North Dakota Generation Cost Recovery Rider Accrued Revenues[2]	470	-	470	12
South Dakota Deferred Rate Case Expenses Subject to Recovery[1]	455	-	455	12
Big Stone II Unrecovered Project Costs – South Dakota[1]	116	263	379	39
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	377	-	377	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	120	222	342	30
Minnesota SPP Transmission Cost Recovery Tracker[1]	-	148	148	see below
Deferred Lease Expenses[1]	-	47	47	45
Minnesota Environmental Cost Recovery Rider Accrued Revenues[2]	4	-	4	12
Minnesota Renewable Resource Recovery Rider Accrued Revenues[2]	3	-	3	12
Total Regulatory Assets	$ 14,501	$ 131,692	$ 146,193	
Regulatory Liabilities:				
Deferred Income Taxes	$ -	$ 140,226	$ 140,226	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	-	83,977	83,977	asset lives
Refundable Fuel Clause Adjustment Revenues – Minnesota	5,087	-	5,087	12
Refundable Fuel Clause Adjustment Revenues – North Dakota	1,676	-	1,676	12
North Dakota Renewable Resource Recovery Rider Accrued Refund	725	-	725	12
North Dakota Environmental Cost Recovery Rider Accrued Refund	614	-	614	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	391	-	391	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	-	284	284	see below
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	94	93	187	18
South Dakota Transmission Cost Recovery Rider Accrued Refund	146	-	146	12
Refundable Fuel Clause Adjustment Revenues – South Dakota	130	-	130	12
South Dakota Environmental Cost Recovery Rider Accrued Refund	45	-	45	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Refund	45	-	45	4
Other	6	75	81	174
Total Regulatory Liabilities	$ 8,959	$ 224,655	$ 233,614	
Net Regulatory Asset/(Liability) Position	$ 5,542	$ (92,963)	$ (87,421)	

[1]*Costs subject to recovery without a rate of return.*

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

(in thousands)	December 31, 2018 Current	Long-Term	Total	Remaining Recovery/ Refund Period (months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$ 6,346	$ 118,433	$ 124,779	see below
Accumulated ARO Accretion/Depreciation Adjustment[1]	-	7,169	7,169	asset lives
Conservation Improvement Program Costs and Incentives[2]	5,995	3,285	9,280	21
Minnesota Transmission Cost Recovery Rider Accrued Revenues[2]	444	-	444	12
Deferred Marked-to-Market Losses[1]	1,661	743	2,404	24
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery[1]	-	986	986	asset lives
Big Stone II Unrecovered Project Costs – Minnesota[1]	681	947	1,628	28
Debt Reacquisition Premiums[1]	207	753	960	165
Deferred Income Taxes[1]	-	2,423	2,423	asset lives
South Dakota Deferred Rate Case Expenses Subject to Recovery[1]	178	-	178	12
Big Stone II Unrecovered Project Costs – South Dakota[1]	100	342	442	53
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	455	-	455	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	240	-	240	12
Minnesota SPP Transmission Cost Recovery Tracker[1]	-	176	176	see below
Minnesota Environmental Cost Recovery Rider Accrued Revenues[2]	121	-	121	12
Minnesota Renewable Resource Recovery Rider Accrued Revenues[2]	452	-	452	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[1]	328	-	328	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	17	-	17	12
Total Regulatory Assets	$ 17,225	$ 135,257	$ 152,482	
Regulatory Liabilities:				
Deferred Income Taxes	$ -	$ 142,779	$ 142,779	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	-	83,229	83,229	asset lives
North Dakota Renewable Resource Recovery Rider Accrued Refund	177	-	177	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	60	-	60	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	-	166	166	see below
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	-	187	187	24
South Dakota Transmission Cost Recovery Rider Accrued Refund	168	-	168	12
South Dakota Environmental Cost Recovery Rider Accrued Refund	207	-	207	12
Refundable Fuel Clause Adjustment Revenues	121	-	121	12
Other	5	108	113	180
Total Regulatory Liabilities	$ 738	$ 226,469	$ 227,207	
Net Regulatory Asset/(Liability) Position	$ 16,487	$ (91,212)	$ (74,725)	

[1]*Costs subject to recovery without a rate of return.*

[2]*Amount 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.

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

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

The Minnesota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are recoverable from Minnesota customers as of June 30, 2019.

All Deferred Marked-to-Market Losses recorded as of June 30, 2019 relate to forward purchases of energy scheduled for delivery through December 2020.

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.

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 159 months.

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

North Dakota Generation Cost Recovery (NDGCR) Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP’s investment in Astoria Station, a natural gas-fired combustion turbine generation facility under construction near Astoria, South Dakota. The June 30, 2019 balance represents amounts subject to recovery from North Dakota customers that have not been billed to North Dakota customers.

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

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 currently being recovered beginning with the establishment of interim rates in January 2018.

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.

The Minnesota SPP Transmission Cost Recovery Tracker regulatory asset relates to costs incurred to serve Minnesota customers that are subject to recovery but that have not been billed to Minnesota customers as of June 30, 2019.

Deferred Lease Expenses: Under ASC 842 accounting rules, for leases with scheduled escalating payments, rent expense is required to be recognized on a straight-line basis over the life of the lease based on the sum of those payments. Rate-regulated entities are generally only allowed to recover the amount of actual cash payments on leases and FERC accounting rules require that rent expense be recognized on the basis of cash payments. The balance in the deferred lease expense regulatory asset account on June 30, 2019 represents operating lease right of use asset cumulative amortization and interest costs in excess of cumulative lease payments that are subject to recovery in future periods under regulatory accounting treatment as cash payments are rendered.

The Minnesota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the Minnesota share of OTP’s investment in the Big Stone Plant AQCS project that are recoverable from Minnesota customers as of June 30, 2019.

The Minnesota Renewable Resource Recovery Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that are recoverable from Minnesota customers as of June 30, 2019. Currently, the rider is only being used to recover the amount of federal PTCs generated by OTP’s wind farms that were transferred from inclusion in the rider and applied as a reduction in revenue requirements to Minnesota base rates. Subsequent to applying the PTCs to base rates the PTCs expired. The Minnesota RRA rider is now being used to recover the shortfall in base rates related to the expiration of the PTCs. Recovery will continue through the rider until interim or revised base rates are established in connection with OTP’s next Minnesota rate case.

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.

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 were recoverable from North Dakota customers as of December 31, 2018.

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

North Dakota Renewable Resource Recovery 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 June 30, 2019.

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 that are refundable to North Dakota customers as of June 30, 2019. Effective February 1, 2019 these rate base investments are being recovered under general rates and the rider was zeroed out except for an overcollection balance that is being refunded to North Dakota ratepayers through the rider.

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 June 30, 2019.

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.

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 June 30, 2019.

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 June 30, 2019.

The Minnesota Energy Intensive Trade Exposed Rider Accrued Refund relates to over-collected amounts from Minnesota retail customers for fuel and purchased power costs reductions provided to customers in energy intensive trade exposed industries that are subject to refund to Minnesota customers.

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. Common Shares and Earnings Per Share

Shelf Registration
On May 3, 2018 the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which the Company 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.

Common Shares
Following is a reconciliation of the Company's common shares outstanding from December 31, 2018 through June 30, 2019:

Common Shares Outstanding, December 31, 2018	39,664,884
Issuances:	
Executive Stock Performance Awards (2016 shares earned)	102,198
Vesting of Restricted Stock Units	26,750
Restricted Stock Issued to Directors	15,700
Directors Deferred Compensation	594
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(55,224)
Common Shares Outstanding, June 30, 2019	39,754,902

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income for the three- and six-month periods ended June 30, 2019 and 2018. 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, 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 reconciliations.

	Three Months ended June 30		Six Months ended June 30	
	2019	2018	2019	2018
Weighted Average Common Shares Outstanding – Basic	39,712,036	39,605,717	39,684,679	39,578,296
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	134,137	202,643	146,148	212,902
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	60,168	57,616	61,783	58,373
Nonvested Restricted Shares	9,657	10,733	15,790	19,188
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	1,833	2,360	2,099	2,617
Total Dilutive Shares	205,795	273,352	225,820	293,080
Weighted Average Common Shares Outstanding – Diluted	39,917,831	39,879,069	39,910,499	39,871,376

The effect of dilutive shares on earnings per share for the three- and six-month periods ended June 30, 2019 and 2018, resulted in no differences greater than $0.01 between basic and diluted earnings per share in any period.

6. Share-Based Payments

Stock Incentive Awards

The following stock incentive awards were granted under the 2014 Stock Incentive Plan during the six-month period ended June 30, 2019:

Award	Grant-Date	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Stock Performance Awards Granted:				
Under Executive and Select Employee Agreements	February 13, 2019	47,800	$ 42.875	December 31, 2021
Under Legacy Agreement	February 13, 2019	7,800	$ 45.885	December 31, 2021
Restricted Stock Units Granted to Executive Officers	February 13, 2019	15,600	$ 49.6225	25% per year through February 6, 2023
Restricted Stock Units Granted to Key Employees	April 8, 2019	13,270	$ 44.45	100% on April 8, 2023
Restricted Stock Granted to Nonemployee Directors	April 8, 2019	15,700	$ 49.73	33% per year through April 8, 2022

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration on retirement 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 granted to an executive officer was the average of the high and low market price per share on the date of grant. The grant-date fair value of each restricted stock unit granted to a key employee that is not an executive officer was the average of the high and low market price per share on the date of grant, discounted for the value of the dividend exclusion on those restricted stock units over the respective vesting periods.

Under the performance share awards the aggregate award for performance at target is 55,600 shares. For target performance the participants would earn an aggregate of 27,800 common shares for achieving the target set for the Company's 3-year average adjusted ROE. The participants would also earn an aggregate of 27,800 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, 2019 through December 31, 2021, 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, 2019 and the average closing price for the 20 trading days immediately preceding January 1, 2022. Actual payment may range from zero to 150% of the target amount, or up to 83,400 common shares. There are no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance measurement period. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC Topic 718, *Compensation – Stock Compensation*, 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.

Under the 2019 Performance Award Agreements, payment and 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 vesting of these awards is accelerated and paid at target in the event of a change in control.

The restricted shares granted to the Company's nonemployee directors are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreements. The grant-date fair value of each restricted share was the average of the high and low market price per share on the date of grant.

The end of the period over which compensation expense is recognized for the above share-based awards for the individual grantees is the earlier 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 June 30, 2019, the remaining unrecognized compensation expense related to outstanding, unvested stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted-average period of 2.3 years.

Amounts of compensation expense recognized under the Company's stock-based payment programs for the three and six-month periods ended June 30, 2019 and 2018 are presented in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Stock Performance Awards Granted to Executive Officers	$ 1,418	$ 668	$ 2,531	$ 1,319
Restricted Stock Units Granted to Executive Officers	383	173	810	422
Restricted Stock Granted to Executive Officers	-	-	-	16
Restricted Stock Granted to Nonemployee Directors	204	165	369	331
Restricted Stock Units Granted to Key Employees	143	101	234	165
Totals	$ 2,148	$ 1,107	$ 3,944	$ 2,253

In July 2019 the Company reinstituted a 15% employee discount under its employee stock purchase plan. The Company estimates the discount will not have a material impact on annual stock-based payment expenses.

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 June 30, 2019, the Company was in compliance with these financial 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 47.9% and 58.5% based on OTP's 2018 capital structure petition effective by order of the MPUC on October 18, 2018. As of June 30, 2019, OTP's equity-to-total-capitalization ratio including short-term debt was 52.8% and its net assets restricted from distribution totaled approximately $490 million.

On May 1, 2019 OTP filed a petition for approval of an equity-to-total capitalization ratio between 46.0% and 56.2% with total capitalization not to exceed $1,331,302,000 in its 2019 capital structure filing. OTP's 2019 capital structure petition was approved and effective by order of the MPUC on July 19, 2019.

8. Leases

The Company adopted ASU 2016-02 and related updates (ASC Topic 842), which replaced previous lease accounting guidance, on January 1, 2019, using the modified retrospective method of adoption. As a result, prior periods have not been restated. ASC Topic 842 requires lessees to record assets and liabilities on the balance sheet for all leases with terms longer than 12 months. Adoption of the standard resulted in the recognition of net lease assets and lease liabilities of$20 million on January 1, 2019. The adoption of the new standard did not have a material effect on the Company's consolidated statements of income or cash flows. In addition, the adoption did not have a material impact on the Company's liquidity or the Company's covenant compliance under its current debt agreements.

The Company elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows for the carry forward of lease classifications determined under the requirements of ASC Topic 840. The Company also elected the practical expedient related to land easements, allowing for the continuation of historical accounting treatment for land easements on existing agreements at OTP. In addition, the Company has elected the hindsight practical expedient to determine the reasonably certain lease term for leases in place at the time of adoption. The Company has elected the practical expedient to not separate nonlease components from lease components on real estate leases for the purpose of determining the classification and the value of lease assets and lease liabilities at the inception of a lease.

The Company enters into leases for coal rail cars, warehouse and office space, land and certain office, manufacturing and material handling equipment under varying terms and conditions. The lengths of the leases vary from less than 1 year to approximately 10 years. If a lease contains an option to extend and there is reasonable certainty the option will be exercised, the option is considered in the lease term at inception. None of these leases met the criteria to be classified as financing leases. Of the operating leases in place on January 1, 2019, 50 were capitalized as right-of-use assets and the remainder were month-to-month leases with no long-term obligations.

The right-of-use asset operating leases in place at the time of adoption were capitalized on the basis of their remaining payment obligation balances, discounted to present value based on the Company's incremental borrowing rates (IBRs) appropriate to the leased asset and lease terms. The remaining payments for operating lease right-of-use assets are being charged to expense on a straight-line basis over the life of the lease.

For the Company's current lease obligations, no explicit interest rates were stated in the lease agreements and no implicit rates could be determined based on the terms of the agreements. Therefore, in all cases, the Company has applied a formula-based IBR appropriate to the individual company, type of lease and lease term.

The breakdown of right-of-use assets and lease liabilities as of June 30, 2019 by business segment is provided in the following table.

(in thousands)	Electric	Manufacturing	Plastics	Corporate	Total
Right of Use Assets – Operating Leases:					
Gross	$ 3,586	$ 16,630	$ 666	$ 769	$ 21,651
Accumulated Amortization	(526)	(1,393)	(195)	(64)	(2,178)
Net of Accumulated Amortization	$ 3,060	$ 15,237	$ 471	$ 705	$ 19,473
Obligations:					
Current Operating Lease Liabilities	$ 975	$ 2,303	$ 353	$ 153	$ 3,784
Long-Term Operating Lease Liabilities	2,336	13,019	118	611	16,084
Total Lease Liabilities	$ 3,311	$ 15,322	$ 471	$ 764	$ 19,868

The amounts of the Company’s right-of-use operating lease obligations for each of the five years in the period 2019 through 2023 and in aggregate for the years beyond 2023 are presented in the following table, including obligations under lease agreements that had not commenced as of June 30, 2019.

	Right-of-Use Operating Leases		
(in thousands)	OTP	Nonelectric	Total
2019	$ 570	$ 2,055	$ 2,625
2020	1,115	3,872	4,987
2021	1,100	3,600	4,700
2022	207	3,465	3,672
2023	196	3,174	3,370
Beyond 2023	447	8,022	8,469
Total Minimum Obligations	$ 3,635	$ 24,188	$ 27,823
Interest Component of Obligations	(314)	(4,115)	(4,429)
Present Value of Leases Commencing after June 30, 2019	(10)	(3,516)	(3,526)
Present Value of Minimum Obligations, June 30, 2019	$ 3,311	$ 16,557	$ 19,868

The Company’s total minimum lease obligations reported in the table above includes obligations for a 10-year lease of a warehouse by T.O. Plastics entered into in 2018 and commencing in July 2019 and a 15-year lease for land on which OTP plans to construct a small solar-electric project with a one-time payment to be made at commencement of the lease in July 2019.

The weighted-average remaining lease term for the Company’s outstanding lease liabilities is 5.8 years and the weighted-average discount rate is 5.0%.

A reconciliation of the Company’s operating lease obligations on adoption of ASC Topic 842 on January 1, 2019 and its operating lease obligations on June 30, 2019 is provided in the table below.

(in thousands)	OTP	Nonelectric	Total
Operating Lease Obligations, January 1, 2019	$ 3,609	$ 16,760	$ 20,369
Non-cash Acquisition of Right-of-Use Assets	167	1,725	1,892
Lease Modifications	-	(1,366)	(1,366)
Lease Obligation Payments	(551)	(992)	(1,543)
Interest Component of Lease Obligation Payment	86	430	516
Operating Lease Obligations, June 30, 2019	$ 3,311	$ 16,557	$ 19,868

The lease modifications in the above table relate to reductions in future minimum lease obligations on several units of leased equipment at BTD.

OTP has obligations to make future operating lease payments primarily related to coal rail-car leases. OTP’s rail-car lease payments are charged to fuel inventory and then expensed to production fuel – electric as a component of fuel cost when fuel is burned. OTP also leases office and operating equipment with lease payments charged to rent expense and reported in electric operation and maintenance expenses on the Company’s consolidated statements of income. From time to time, OTP will lease construction equipment or land for lay-down yards for materials used on capital projects. These leases are generally short term in nature with the lease payments being charged to the related construction project and included in CWIP or plant in service after the project is completed and placed in service.

The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment. These payments are charged to rent expense accounts and reported in costs of goods sold or other nonelectric expenses, as appropriate, on the Company's consolidated statements of income.

The allocation of right-of-use asset and variable lease costs, including non-cash costs related to straight-line amortization of escalating lease payments, for the three- and six-month periods ending June 30, 2019 is presented in the following table.

	Three Months Ended June 30, 2019			Six Months Ended June 30, 2019		
	Operating Lease Cost	Variable Lease Cost	Total Lease Cost	Operating Lease Cost	Variable Lease Cost	Total Lease Cost
Plant in Service or CWIP	$ 11	$ -	$ 11	$ 20	$ -	$ 20
Inventory	238	-	238	463	-	463
Cost of Products Sold	943	45	988	1,979	72	2,051
Electric Operation and Maintenance Expenses	64	-	64	130	-	130
Other Nonelectric Expenses	51	1	52	105	1	106
Total	1,307	$ 46	$ 1,353	$ 2,697	$ 73	$ 2,770

9. Commitments and Contingencies

Construction and Other Purchase Commitments
At June 30, 2019 OTP had commitments under contracts, including its share of construction program commitments and other nonlease commitments, extending into 2021 of approximately $77.3 million. At December 31, 2018 OTP had commitments under contracts, including its share of construction program commitments and other nonlease commitments, extending into 2021 of approximately $64.5 million. At June 30, 2019 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately $4.1 million. At December 31, 2018 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately $5.0 million.

Electric Utility Capacity and Energy Requirements and Coal Purchase and Delivery Contracts
OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2042. OTP also has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Coyote Station expire at the end of 2040. OTP's current coal purchase agreements for Big Stone Plant expire at the end of 2020. OTP has an agreement with Peabody COALSALES, LLC for the purchase of subbituminous coal for Big Stone Plant's coal requirements through December 31, 2020. There is no fixed minimum purchase requirement under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement, except for a portion contracted to be purchased in 2019 under a prior existing agreement with Contura Coal Sales, LLC. OTP has an all-requirements agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. There are no fixed minimum purchase requirements under this agreement.

OTP Land Easements
OTP has commitments to make future payments for land easements not classified as leases, extending into 2034 of approximately $10.5 million.

Contingencies
OTP had a $1.6 million refund liability on its balance sheet as of June 30, 2019 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. As discussed in note 3 in greater detail, OTP believes its estimated accrued refund liability is appropriate based on the current facts and circumstances and is awaiting further action by the FERC before determining if a change in this estimate will be needed.

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 potential ROE refund described above, the most significant contingencies that could impact the Company's consolidated financial statements are those related to environmental remediation, risks associated with warranty claims relating to divested businesses that could exceed established reserve amounts, and litigation matters. The Company currently is not aware of any items that would result in charges in excess of established reserve amounts.

In 2015 the Environmental Protection Agency (EPA), acting under Section 111(d) of the Clean Air Act, issued the Clean Power Plan which required states to submit plans to limit carbon dioxide emissions from certain fossil fuel-fired power plants. The rule is not currently in effect as a result of a stay by the Supreme Court in 2016. In 2017, the EPA issued a Notice of Proposed Rulemaking to repeal the Clean Power Plan; comments were due in April 2018.

On August 21, 2018 the EPA proposed a replacement for the Clean Power Plan -- the Affordable Clean Energy (ACE) Rule. Among other things, the proposed ACE Rule identifies a list of “candidate technologies” for improving a plant’s heat rate and proposes that physical or operational changes to a power plant would not be a “major modification” triggering extensive New Source Review, if the change does increase hourly emissions. On June 19, 2019 the EPA released the final version of the ACE Rule, which will be effective on September 6, 2019. The final ACE Rule establishes guidelines for states to use in developing plans to address greenhouse gas emissions from existing coal-fired power plants and was finalized in conjunction with two related but separate and distinct rulemakings, which include repealing the Clean Power Plan and providing revisions to state implementation plan guidance. The ACE Rule establishes heat rate improvements, or efficiency improvements, as the best system of emissions reduction for carbon dioxide from existing coal-fired generation units. Heat rate is a measure of the amount of energy required to generate a unit of electricity. States will establish unit-specific standards of performance that reflect the emission limitation achievable through certain candidate heat-rate improvement technologies. The final ACE Rule did not include any final action regarding New Source Review. The EPA intends to address the proposed New Source Rule reforms in a separate final action.

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 June 30, 2019 will not be material.

10. Short-Term and Long-Term Borrowings

The following table presents the status of the Company's lines of credit as of June 30, 2019 and December 31, 2018:

(in thousands)	Line Limit	In Use on June 30, 2019	Restricted due to Outstanding Letters of Credit	Available on June 30, 2019	Available on December 31, 2018
Otter Tail Corporation Credit Agreement	$ 130,000	$ 13,801	$ -	$ 116,199	$ 120,785
OTP Credit Agreement	170,000	22,801	8,766	138,433	160,316
Total	$ 300,000	$ 36,602	$ 8,766	$ 254,632	$ 281,101

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of June 30, 2019 and December 31, 2018:

June 30, 2019 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$ 22,801	$ 13,801	$ 36,602
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
PACE Note, 2.54%, due March 18, 2021		438	438
Total	$ 512,000	$ 80,438	$ 592,438
Less: Current Maturities net of Unamortized Debt Issuance Costs	-	177	177
Unamortized Long-Term Debt Issuance Costs	1,816	382	2,198
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$ 510,184	$ 79,879	$ 590,063
Total Short-Term and Long-Term Debt (with current maturities)	$ 532,985	$ 93,857	$ 626,842

December 31, 2018 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$ 9,384	$ 9,215	$ 18,599
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
PACE Note, 2.54%, due March 18, 2021		523	523
Total	$ 512,000	$ 80,523	$ 592,523
Less: Current Maturities net of Unamortized Debt Issuance Costs	-	172	172
Unamortized Long-Term Debt Issuance Costs	1,942	407	2,349
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$ 510,058	$ 79,944	$ 590,002
Total Short-Term and Long-Term Debt (with current maturities)	$ 519,442	$ 89,331	$ 608,773

11. 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:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Service Cost—Benefit Earned During the Period	$ 1,373	$ 1,615	2,746	$ 3,230
Interest Cost on Projected Benefit Obligation	3,603	3,363	7,206	6,726
Expected Return on Assets	(5,324)	(5,299)	(10,649)	(10,599)
Amortization of Prior-Service Cost:				
From Regulatory Asset	2	4	3	8
From Other Comprehensive Income[1]	2	-	4	-
Amortization of Net Actuarial Loss:				
From Regulatory Asset	1,162	1,783	2,325	3,567
From Other Comprehensive Income[1]	26	47	53	91
Net Periodic Pension Cost[2]	$ 844	$ 1,513	$ 1,688	$ 3,023
[1]*Corporate cost included in nonservice cost components of postretirement benefits.*				
[2]*Allocation of Costs:*				
Costs included in OTP capital expenditures	*$* 336	*$* 379	*$* 726	*$* 707
Service costs included in electric operation and maintenance expenses	1,004	1,195	1,954	2,442
Service costs included in other nonelectric expenses	33	40	66	80
Nonservice costs capitalized as regulatory assets	(130)	(24)	(280)	(45)
Nonservice costs included in nonservice cost components of postretirement benefits	(399)	(77)	(778)	(161)

Cash flows—The Company had no minimum funding requirement as of December 31, 2018 but made a discretionary plan contribution of $10 million in January 2019.

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:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Service Cost—Benefit Earned During the Period	$ 104	$ 100	$ 209	$ 200
Interest Cost on Projected Benefit Obligation	434	399	868	798
Amortization of Prior-Service Cost:				
From Regulatory Asset	1	4	2	8
From Other Comprehensive Income[1]	4	9	8	19
Amortization of Net Actuarial Loss:				
From Regulatory Asset	31	67	62	134
From Other Comprehensive Income[1]	88	165	175	330
Net Periodic Pension Cost[2]	$ 662	$ 744	$ 1,324	$ 1,489
[1]*Amortization of prior service costs and net actuarial losses from other comprehensive income are included in nonservice cost components of postretirement benefits.*				
[2]*Allocation of Costs:*				
Service costs included in electric operation and maintenance expenses	*$* 26	*$* 25	*$* 52	*$* 50
Service costs included in other nonelectric expenses	78	75	157	150
Nonservice costs included in nonservice cost components of postretirement benefits	558	644	1,115	1,289

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Service Cost—Benefit Earned During the Period	$ 322	$ 381	$ 643	$ 763
Interest Cost on Projected Benefit Obligation	772	646	1,542	1,291
Amortization of Net Actuarial Loss:				
From Regulatory Asset	392	412	785	824
From Other Comprehensive Income[1]	9	11	19	21
Net Periodic Postretirement Benefit Cost[2]	$ 1,495	$ 1,450	$ 2,989	$ 2,899
Effect of Medicare Part D Subsidy	$ (44)	$ (36)	$ (89)	$ (73)
[1]*Corporate cost included in nonservice cost components of postretirement benefits.*				
[2]*Allocation of Costs:*				
Costs included in OTP capital expenditures	*$* 79	*$* 89	*$* 170	*$* 167
Service costs included in electric operation and maintenance expenses	235	283	458	577
Service costs included in other nonelectric expenses	8	9	15	19
Nonservice costs capitalized as regulatory assets	288	251	621	468
Nonservice costs included in nonservice cost components of postretirement benefits	885	818	1,725	1,668

12. 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 June 30, 2019 and December 31, 2018 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.

	June 30, 2019		December 31, 2018	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$ 982	$ 982	$ 861	$ 861
Short-Term Debt	(36,602)	(36,602)	(18,599)	(18,599)
Long-Term Debt including Current Maturities	(590,240)	(631,747)	(590,174)	(601,513)

13. Property, Plant and Equipment

No update required for interim reporting period.

14. Income Tax Expense

The following table provides a reconciliation of income tax expense calculated at the net composite federal and state statutory rate on income before income taxes and income tax expense reported on the Company's consolidated statements of income for the three- and six-month periods ended June 30, 2019 and 2018:

(in thousands)	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
Income Before Income Taxes	$ 18,769	$ 21,750	$ 50,721	$ 51,759
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26%)	$ 4,879	$ 5,655	$ 13,187	$ 13,457
Decreases in Tax from:				
Differences Reversing in Excess of Federal Rates	(774)	(1,025)	(1,757)	(2,098)
Excess Tax Deduction – Equity Method Stock Awards	-	-	(827)	(624)
Corporate Owned Life Insurance	(150)	(17)	(559)	(25)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(258)	(516)	(516)
Research and Development and Other Tax Credits	(187)	(180)	(375)	(360)
Allowance for Funds Used During Construction – Equity	(94)	(111)	(180)	(278)
Federal Production Tax Credits	-	(930)	-	(2,050)
Other Comprehensive Income Deferred Tax Rate Adjustment	-	-	-	(531)
Other Items – Net	(73)	(80)	(2)	(127)
Income Tax Expense	$ 3,343	$ 3,054	$ 8,971	$ 6,848
Effective Income Tax Rate	17.8%	14.0%	17.7%	13.2%

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

(in thousands)	2019	2018
Balance on January 1	$ 1,282	$ 684
Decreases Related to Tax Positions for Prior Years	-	-
Increases Related to Tax Positions for Current Year	75	72
Uncertain Positions Resolved During Year	(42)	(44)
Balance on June 30	$ 1,315	$ 712

The balance of unrecognized tax benefits as of June 30, 2019 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of June 30, 2019 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 June 30, 2019.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of August 1, 2019, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2015 for federal, Minnesota and North Dakota income taxes.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

RESULTS 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 and six months ended June 30, 2019 and 2018 followed by a discussion of changes in our consolidated financial position during the six months ended June 30, 2019 and our business outlook for the remainder of 2019.

Comparison of the Three Months Ended June 30, 2019 and 2018

Consolidated operating revenues were $229.2 million for the three months ended June 30, 2019 compared with $226.3 million for the three months ended June 30, 2018. Operating income was $26.8 million for the three months ended June 30, 2019 compared with $30.1 million for the three months ended June 30, 2018. The Company recorded diluted earnings per share of $0.39 for the three months ended June 30, 2019 compared with $0.47 for the three months ended June 30, 2018.

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 June 30, 2019 and 2018 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:

Intersegment Eliminations *(in thousands)*	June 30, 2019	June 30, 2018
Operating Revenues:		
Electric	$ 14	$ 6
Nonelectric	(1)	1
Costs of Products Sold	3	2
Other Nonelectric Expenses	10	5

Electric

(in thousands)	Three Months Ended June 30, 2019	2018	Change	% Change
Retail Sales Revenues from Contracts with Customers	$ 87,976	$ 89,400	$ (1,424)	(1.6)
Changes in Accrued Revenues under Alternative Revenue Programs	369	(1,565)	1,934	123.6
Total Retail Sales Revenue	$ 88,345	$ 87,835	$ 510	0.6
Transmission Services Revenue	11,469	11,313	156	1.4
Wholesale Revenues – Company Generation	941	2,539	(1,598)	(62.9)
Other Revenues	1,489	2,038	(549)	(26.9)
Total Operating Revenues	$ 102,244	$ 103,725	$ (1,481)	(1.4)
Production Fuel	8,296	15,888	(7,592)	(47.8)
Purchased Power – System Use	19,633	14,402	5,231	36.3
Electric Operation and Maintenance Expenses	39,856	37,741	2,115	5.6
Depreciation and Amortization	15,082	13,979	1,103	7.9
Property Taxes	3,900	3,273	627	19.2
Operating Income	$ 15,477	$ 18,442	$ (2,965)	(16.1)
Electric Megawatt-hour (mwh) Sales				
Retail mwh Sales	1,088,052	1,136,326	(48,274)	(4.2)
Wholesale mwh Sales – Company Generation	42,805	95,475	(52,670)	(55.2)
Heating Degree Days	580	675	(95)	(14.1)
Cooling Degree Days	104	228	(124)	(54.4)

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

	Three Months ended June 30, 2019	2018
Heating Degree Days	112.6%	133.7%
Cooling Degree Days	95.4%	221.4%

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kilowatt-hour (kwh) sales under actual weather conditions and expected retail kwh sales under normal weather conditions in the second quarters of 2019 and 2018 and between quarters:

	2019 vs Normal	2018 vs Normal	2019 vs 2018
Effect on Diluted Earnings Per Share	$ 0.01	$ 0.04	$ (0.03)

The $0.5 million increase in retail sales revenue includes:

- A $1.1 million increase in Minnesota retail revenue due to lower provisions for Tax Cuts and Jobs Act (TCJA) refunds.The effect of lower tax expense recovery requirements was rolled into Minnesota base rates beginning in June 2019.

- A $1.0 million increase in transmission cost recovery revenues, in large part due to the recovery of investment and operating costs of the Big Stone South-Ellendale 345-kilovolt transmission line energized on February 6, 2019.

- A $0.7 million increase in South Dakota revenues related to an interim rate increase that went into effect on October 18, 2018.

- A $0.7 million increase in Minnesota Renewable Rider revenues due to increased cost recovery requirements resulting from the expiration of federal Production Tax Credits (PTCs) in November 2018 on a company-owned wind farm.

- A $0.3 million increase in Minnesota Conservation Improvement Program (MNCIP) cost recovery revenues due to an increase in MNCIP recoverable expenditures in the second quarter of 2019.

- A $0.2 million increase in accrued revenue related to the establishment of a generation cost recovery rider in North Dakota (the NDGCR rider) to provide for a return on funds invested in building Astoria Station during its construction phase. The NDGCR rider will be included in North Dakota customer billings beginning in July 2019.

partially offset by:

- A $1.9 million decrease in retail revenues related to decreased consumption due to milder weather in the second quarter of 2019 compared to warmer than normal weather in May and June of 2018 reflected in a 54.4% decrease in cooling degree days between quarters, and colder weather in April of 2018 reflected in a 14.1% decrease in heating degree days between quarters.

- A $0.8 million reduction in retail revenue due to decreased kwh sales, primarily to commercial and industrial customers, exclusive of the weather-related decrease in retail kwh sales.

- A $0.7 million decrease in retail revenue related to the recovery of decreased fuel and purchased power costs mainly related to the 4.2% decrease in retail kwh sales.

Wholesale electric revenues decreased $1.6 million due to fewer opportunities for wholesale sales as OTP’s Coyote Station was offline during the entire second quarter of 2019 due to an extended maintenance outage. Also, wholesale demand was down due to a milder spring in 2019, which also resulted in lower wholesale electricity prices.

Production fuel costs decreased $7.6 million mainly as a result of a 47.1% decrease in kwhs generated from our fuel burning plants due to the maintenance outage at Coyote Station and a 43.3% reduction in generation at Hoot Lake Plant due to maintenance issues and reduced opportunities for economic dispatch resulting from lower wholesale demand and lower wholesale energy prices due to milder spring weather in 2019.

The cost of purchased power to serve retail customers increased $5.2 million (36.3%) due to a 66.4% increase in kwhs purchased as a result of needing to purchase replacement power during Coyote Station’s maintenance outage and reduced availability of Hoot Lake Plant due to maintenance issues. The increased costs due to the increase in kwhs purchased was partially mitigated by an 18.1% decrease in the cost per kwh purchased resulting from lower wholesale energy prices due to the market factors addressed above.

Table of Contents

Electric operating and maintenance expense increased $2.1 million including:

- A $2.6 million increase in external maintenance costs and material and operating supply expenses in connection with the maintenance outage at Coyote Station over the entire second quarter of 2019.

- A $0.6 million increase in transmission services expenses mainly related to cost reductions and billing adjustments recorded in 2018.

- A $0.3 million increase in external maintenance costs and material and operating supply expenses at Hoot Lake Plant in connection with an unplanned outage in the second quarter of 2019 for turbine repairs.

partially offset by:

- A $0.9 million decrease in storm damage repair expenses, including tree trimming and removal costs, due to a large storm in 2018 that impacted OTP's service area.

- A $0.5 million decrease in expenses related to additional software licensing costs incurred in the second quarter of 2018.

Property tax expense increased $0.6 million due to capital additions, mainly transmission assets, in South Dakota and Minnesota.

Depreciation and amortization expense increased $1.1 million mainly due to 2018 capital additions of transmission plant and the new customer information system put in service in 2019.

Manufacturing

	Three Months Ended June 30,			
(in thousands)	2019	2018	Change	% Change

Operating Revenues	$ 73,496	$ 68,154	$ 5,342	7.8
Cost of Products Sold	56,364	51,844	4,520	8.7
Operating Expenses	7,954	7,439	515	6.9
Depreciation and Amortization	3,419	3,760	(341)	(9.1)
Operating Income	$ 5,759	$ 5,111	$ 648	12.7

The $5.3 million increase in revenues in our Manufacturing segment includes the following:

- Revenues at BTD Manufacturing, Inc. (BTD) increased $3.9 million due to growth in parts revenue of $4.5 million driven by increased sales in construction, recreational vehicle and agricultural end markets, partially offset by decreased sales in energy end markets. Included in the parts revenue increase is the pass-through of higher material costs of $4.2 million, with the remaining increase due to higher sales volume. Revenues from scrap metal sales were down $0.6 million (29%) quarter over quarter due to a 28% decrease in scrap metal prices on a less than 1% decrease in scrap volume.

- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased $1.4 million primarily due to a $1.8 million increase in sales of horticultural containers, partially offset by a $0.4 million decrease in industrial sales. The increase in horticultural sales volume is due to an early order program offered to customers during the second quarter, a catch up on shipments that were delayed due to inclement weather in the first quarter of 2019 and growth of plug tray sales to certain horticultural markets. Industrial sales were down due to a customer bringing more production in house.

The $4.5 million increase in cost of products sold in our Manufacturing segment includes the following:

- Cost of products sold at BTD increased $3.2 million resulting from both the $4.2 million in higher material costs passed through to customers and increased sales volume, partially offset by a $1.4 million increase in recovery of tooling costs from customers.

- Cost of products sold at T.O. Plastics increased $1.3 million due to the increase in sales volume.

The $0.5 million increase in operating expenses in our Manufacturing segment includes a $0.4 million increase at BTD mainly from increases in labor-related costs due to additional employees. Operating expenses at T.O. Plastics increased $0.1 million due to an increase in sales and marketing costs. Depreciation and amortization expense at BTD decreased $0.3 million as a result of certain assets reaching the ends of their depreciable lives.

Table of Contents

Plastics

(in thousands)	Three Months Ended June 30, 2019	2018	Change	% Change
Operating Revenues	$ 53,476	$ 54,476	$ (1,000)	(1.8)
Cost of Products Sold	41,635	41,703	(68)	(0.2)
Operating Expenses	2,949	3,262	(313)	(9.6)
Depreciation and Amortization	861	954	(93)	(9.7)
Operating Income	$ 8,031	$ 8,557	$ (526)	(6.1)

Plastics segment revenues and operating income decreased $1.0 million and $0.5 million, respectively, due to a 3.6% decrease in polyvinyl chloride (PVC) pipe prices partially offset by a 1.9% increase in pounds of pipe sold. The quarter-over-quarter sales volume increase was due to stronger demand for product in southcentral and southwestern regions of the United States, offset by lower volumes with certain customers in the northern region of our sales territory. Cost of products sold decreased $0.1 million despite the increase in sales volume due to 2.0% decrease in the cost per pound of pipe sold. The decrease in pipe prices in excess of the decrease in costs per pound of pipe sold resulted in a 9.0% decrease in gross margin per pound of PVC pipe sold. Plastics segment operating expenses decreased $0.3 million between the quarters mainly due to lower incentive compensation resulting from a decrease in operating income.

Corporate

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.

(in thousands)	Three Months Ended June 30, 2019	2018	Change	% Change
Operating Expenses	$ 2,369	$ 1,953	$ 416	21.3
Depreciation and Amortization	79	52	27	51.9

Corporate operating expenses increased $0.4 million mainly due to an increase in certain employee benefit costs.

Income Tax Expense

Income tax expense increased $0.3 million in the three months ended June 30, 2019 compared with the three months ended June 30, 2018 mainly due to a $0.9 million decrease in federal PTCs resulting from the expiration of PTCs on OTP’s Ashtabula wind farm in November 2018, partially offset by the tax effect of a $3.0 million decrease in income 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 before income taxes on our consolidated statements of income.

(in thousands)	Three Months Ended June 30, 2019	2018
Income Before Income Taxes	$ 18,769	$ 21,750
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26%)	$ 4,879	$ 5,655
Decreases in Tax from:		
Differences Reversing in Excess of Federal Rates	(774)	(1,025)
Corporate Owned Life Insurance	(150)	(17)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(258)	(258)
Research and Development and Other Tax Credits	(187)	(180)
Allowance for Funds Used During Construction – Equity	(94)	(111)
Federal Production Tax Credits	-	(930)
Other Items – Net	(73)	(80)
Income Tax Expense	$ 3,343	$ 3,054
Effective Income Tax Rate	17.8%	14.0%

Table of Contents

Comparison of the Six Months Ended June 30, 2019 and 2018

Consolidated operating revenues were $475.2 million for the six months ended June 30, 2019 compared with $467.6 million for the six months ended June 30, 2018. Operating income was $66.4 million for the six months ended June 30, 2019 compared with $67.7 million for the six months ended June 30, 2018. The Company recorded diluted earnings per share of $1.05 for the six months ended June 30, 2019 compared with $1.13 for the six months ended June 30, 2018.

Amounts presented in the segment tables that follow for operating revenues, cost of products sold and other nonelectric operating expenses for the six-month periods ended June 30, 2019 and 2018 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:

Intersegment Eliminations *(in thousands)*	June 30, 2019	June 30, 2018
Operating Revenues:		
Electric	$ 27	$ 21
Nonelectric	3	-
Costs of Products Sold	20	7
Other Nonelectric Expenses	10	14

Electric

(in thousands)	Six Months Ended June 30, 2019	2018	Change	% Change
Retail Sales Revenues from Contracts with Customers	$ 202,931	$ 198,580	$ 4,351	2.2
Changes in Accrued Revenues under Alternative Revenue Programs	(680)	(2,440)	1,760	(72.1)
Total Retail Sales Revenue	$ 202,251	$ 196,140	$ 6,111	3.1
Transmission Services Revenue	22,331	23,216	(885)	(3.8)
Wholesale Revenues – Company Generation	2,468	3,554	(1,086)	(30.6)
Other Revenues	3,303	3,780	(477)	(12.6)
Total Operating Revenues	$ 230,353	$ 226,690	$ 3,663	1.6
Production Fuel	27,216	34,594	(7,378)	(21.3)
Purchased Power – System Use	41,585	35,995	5,590	15.5
Other Operation and Maintenance Expenses	78,238	77,216	1,022	1.3
Depreciation and Amortization	29,567	27,901	1,666	6.0
Property Taxes	7,859	7,108	751	10.6
Operating Income	$ 45,888	$ 43,876	$ 2,012	4.6
Electric mwh Sales				
Retail mwh Sales	2,566,191	2,590,219	(24,028)	(0.9)
Wholesale mwh Sales – Company Generation	82,139	134,879	(52,740)	(39.1)
Heating Degree Days	4,650	4,266	384	9.0
Cooling Degree Days	104	228	(124)	(54.4)

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

	Six Months ended June 30, 2019	2018
Heating Degree Days	118.6%	110.1%
Cooling Degree Days	95.4%	221.4%

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 six months of 2019 and 2018 and between the periods:

	2019 vs Normal		2018 vs Normal		2019 vs 2018	
Effect on Diluted Earnings Per Share	$	0.08	$	0.06	$	0.02

The $6.1 million increase in retail revenue includes:

- A $1.8 million increase in South Dakota revenues related to an interim rate increase that went into effect on October 18, 2018.
- A $1.7 million increase in retail revenue in South Dakota due to the reversal of a tax refund provision in connection with OTP's 2018 South Dakota rate case settlement agreement.
- A $1.5 million increase in Minnesota Renewable Rider revenues due to increased cost recovery requirements resulting from the expiration of federal PTCs in November 2018 on a second company-owned wind farm.
- A $1.1 million increase in Minnesota TCR rider revenues related to the recovery of investment and operating costs of the Big Stone South–Ellendale 345kV transmission line energized on February 6, 2019.
- A $1.0 million increase in Minnesota retail revenue due to a reduction in the provision for refunds related to lower tax expense under the TCJA. The effect of lower tax expense recovery requirements was rolled into Minnesota base rates beginning in June 2019.
- A $0.9 million increase in revenues mainly related to increased consumption due to colder weather in the first quarter of 2019 compared to the first quarter of 2018, partially offset by the effect on consumption of milder weather in the second quarter of 2019 compared to warmer than normal weather in the second quarter of 2018.
- A $0.5 million increase in accrued revenue related to the establishment of the NDGCR rider to provide for a return on funds invested in the construction of Astoria Station during construction. The NDGCR rider will be included in North Dakota customer billings beginning in July 2019.

partially offset by:

- A $2.2 million reduction in revenue due to a decrease in kwh sales, primarily to commercial and industrial customers, exclusive of the weather-related increase in retail kwh sales.
- A $0.3 million decrease in retail revenue related to the recovery of decreased fuel and purchased power costs mainly related to a 0.9% decrease in retail kwh sales.

Transmission services revenue decreased $0.9 million mainly due to a decrease in MISO tariff revenue related to decreases in levels of recoverable transmission costs incurred.

Wholesale electric revenues decreased $1.1 million resulting from a 39.1% decrease in wholesales kwh sales due to fewer opportunities for wholesale sales as Coyote Station was offline during the entire second quarter of 2019 due to an extended maintenance outage.

Production fuel costs decreased $7.4 million mainly as a result of a 21.3% decrease in kwhs generated from our fuel burning plants due to the maintenance outage at Coyote Station in the second quarter of 2019 and a 7.6% reduction in generation at Hoot Lake Plant due to maintenance issues in the second quarter of 2019.

The cost of purchased power to serve retail customers increased $5.6 million (15.5%) due to a 22.9% increase in kwhs purchased as a result of needing to purchase replacement power during Coyote Station’s maintenance outage and reduced availability of Hoot Lake Plant due to maintenance issues. The increased costs due to the increase in kwhs purchased was partially mitigated by a 6.0% decrease in the cost per kwh purchased resulting from lower wholesale energy prices.

Electric operating and maintenance expense increased $1.0 million including:

- A $2.8 million increase in external maintenance costs and material and operating supply expenses at Coyote Station in connection with the maintenance outage.
- A $1.3 million increase in transmission services expenses mainly related to cost reductions and billing adjustments recorded in 2018.

partially offset by:

- A $1.7 million decrease in storm damage repair expenses, including tree trimming and removal costs, related to a large storm in 2018 that impacted OTP's service territory.
- A $0.6 million decrease in postretirement benefit service costs.
- A $0.5 million decrease in expenses related to additional software licensing costs incurred in the second quarter of 2018.
- A $0.3 million increase in deferred expenses subject to recovery in future periods related to the South Dakota rate case.

Property tax expense increased $0.8 million due to capital additions in South Dakota and Minnesota.

Depreciation expense increased $1.7 million due to recent capital additions including the Big Stone South–Ellendale 345kV transmission line energized in February 2019, the new customer information system put in service in 2019 and other recent transmission plant upgrades.

Manufacturing

	Six Months Ended June 30,			
(in thousands)	2019	2018	Change	% Change
Operating Revenues	$ 151,318	$ 136,816	$ 14,502	10.6
Cost of Products Sold	115,603	103,885	11,718	11.3
Operating Expenses	16,034	14,312	1,722	12.0
Depreciation and Amortization	7,101	7,614	(513)	(6.7)
Operating Income	$ 12,580	$ 11,005	$ 1,575	14.3

The $14.5 million increase in revenues in our Manufacturing segment includes the following:

- Revenues at BTD increased $14.3 million, due to growth in parts revenue of $16.0 million, including increased sales in construction, recreational vehicle, agricultural, and lawn and garden end markets. Included in the parts revenue increase is the pass through of higher material costs of $10.5 million, with the remaining increase due to higher sales volume and an increase in pricing unrelated to material cost increases. The increase in parts revenue was partially offset by a $1.3 million decrease in tooling revenues and a $0.6 million (15%) decrease in revenue from scrap metal sales due to an 18% decrease in scrap metal prices, partially offset by a 3.5% increase in scrap volume.

- Revenues at T.O. Plastics increased $0.2 million primarily due to a $1.0 million increase from sales of horticultural containers, mostly offset by a $0.7 million decrease in industrial sales. The increase in horticultural sales is due to an early order program offered to customers during the second quarter and growth of plug tray sales in certain horticultural markets. Industrial sales were down mainly due to a customer bringing more production in house.

The $11.7 million increase in cost of products sold in our Manufacturing segment includes the following:

- Cost of products sold at BTD increased $11.1 million resulting from both the $10.5 million in higher material costs passed through to customers and increased sales volume, partially offset by a $4.0 million increase in recovery of tooling costs from customers.

- Cost of products sold at T.O. Plastics increased $0.6 million mainly due to increased labor costs driven in part by increased production hours in response to higher sales volume and in part by wage increases.

The $1.7 million increase in operating expenses in our Manufacturing segment includes a $1.4 million increase at BTD mainly from increases in labor-related costs due to additional employees. Operating expenses at T.O. Plastics increased $0.3 million due to a loss associated with the partial collapse of a warehouse roof in the first quarter of 2019 and increased sales and marketing expenditures.

Plastics

	Six Months Ended June 30,			
(in thousands)	2019	2018	Change	% Change
Operating Revenues	$ 93,534	$ 104,129	$ (10,595)	(10.2)
Cost of Products Sold	72,995	78,452	(5,457)	(7.0)
Operating Expenses	5,614	5,876	(262)	(4.5)
Depreciation and Amortization	1,752	1,905	(153)	(8.0)
Operating Income	$ 13,173	$ 17,896	$ (4,723)	(26.4)

Plastics segment revenues decreased $10.6 million due to a 7.1% decrease in pounds of PVC pipe sold and a 3.3% decrease in PVC pipe prices. Because of record first quarter sales volume in 2018, the overall decrease in year-over-year sales volume was expected. Weather conditions across our sales territory also negatively impacted first quarter 2019 sales. Cost of products sold decreased $5.5 million due to the decrease in sales volume with no change in the cost per pound of pipe sold between periods. The decrease in pipe prices resulted in a 13.9% decrease in gross margin per pound of PVC pipe sold. Plastics segment operating expenses decreased $0.3 million between periods mainly due to a decrease in incentive compensation related to the decrease in operating income.

Corporate

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.

	Six Months Ended June 30,			
(in thousands)	2019	2018	Change	% Change
Operating Expenses	$ 5,101	$ 4,969	$ 132	2.7
Depreciation and Amortization	152	88	64	72.7

Interest Charges

The $0.6 million increase in interest charges for the six months ended June 30, 2019 compared with the six months ended June 30, 2018 is due to a $10.6 million increase in average debt outstanding between the periods, the replacement of $100 million of short-term debt bearing interest at 2.88% with long-term debt bearing interest at 4.07% in February 2018 and an increase in average short-term debt interest rates of approximately 1.1% between periods. A $0.1 million decrease in capitalized interest at OTP also contributed to the increase in interest charges between the quarters.

Nonservice Cost Components of Postretirement Benefits

The $0.7 million decrease in nonservice cost components of postretirement benefits in the six months ended June 30, 2019 compared with the six months ended June 30, 2018, is mostly due to a decrease in nonservice costs of the Company's pension plans, mainly actuarial loss amortization expenses.

Income Taxes

Income tax expense increased $2.1 million in the six months ended June 30, 2019 compared with the six months ended June 30, 2018 mainly due to a $2.0 million decrease in federal PTCs resulting from the expiration of PTCs on OTP's Ashtabula wind farm in November 2018. The following table provides a reconciliation of income tax expense calculated at our net composite federal and state statutory rate on income before income taxes on our consolidated statements of income for the three-month periods ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
(in thousands)	2019	2018
Income Before Income Taxes	$ 50,721	$ 51,759
Tax Computed at Company's Net Composite Federal and State Statutory Rate (26%)	$ 13,187	$ 13,457
Decreases in Tax from:		
Differences Reversing in Excess of Federal Rates	(1,757)	(2,098)
Excess Tax Deduction – Equity Method Stock Awards	(827)	(624)
Corporate Owned Life Insurance	(559)	(25)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(516)	(516)
Research and Development and Other Tax Credits	(375)	(360)
Allowance for Funds Used During Construction – Equity	(180)	(278)
Federal Production Tax Credits	-	(2,050)
Other Comprehensive Income Deferred Tax Rate Adjustment	-	(531)
Other Items – Net	(2)	(127)
Income Tax Expense	$ 8,971	$ 6,848
Effective Income Tax Rate	17.7%	13.2%

FINANCIAL POSITION

The following table presents the status of our lines of credit as of June 30, 2019 and December 31, 2018:

(in thousands)	Line Limit	In Use on June 30, 2019	Restricted due to Outstanding Letters of Credit	Available on June 30, 2019	Available on December 31, 2018
Otter Tail Corporation Credit Agreement	$ 130,000	$ 13,801	$ -	$ 116,199	$ 120,785
OTP Credit Agreement	170,000	22,801	8,766	138,433	160,316
Total	$ 300,000	$ 36,602	$ 8,766	$ 254,632	$ 281,101

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 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.

Equity or debt financing will be required in the period 2019 through 2023 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.

Table of Contents

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, 2019 our board of directors increased the quarterly dividend from $0.335 to $0.35 per common share.

Cash provided by operating activities was $69.3 million for the six months ended June 30, 2019 compared with $53.4 million for the six months ended June 30, 2018. The primary reasons for the $15.9 million increase in cash provided by operations between the quarters was a $10.0 million decrease in discretionary contributions to the corporation’s funded pension plan and a $12.7 million net increase in cash provided by changes in noncurrent liabilities and deferred credits, partially offset by a $6.4 million decrease in cash from changes in deferred debits and other assets between the periods.

Net cash used in investing activities was $55.4 million for the six months ended June 30, 2019 compared with $49.7 million for the six months ended June 30, 2018. The $5.7 million increase in cash used for investing activities includes a $3.7 million increase in capital expenditures at OTP and a $1.7 million increase in capital expenditures at BTD.

Net cash used in financing activities was $13.8 million for the six months ended June 30, 2019 compared with $18.9 million for the six months ended June 30, 2018. Financing activities in the first six months of 2019 included proceeds of $13.4 million from borrowings under the OTP credit agreement to fund OTP capital expenditures and $4.6 million under the Otter Tail Corporation Credit Agreement to provide working capital for our manufacturing companies. The line of credit borrowings were more than offset by $27.9 million in common dividend payments.

Financing activities in the first six months 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 capital expenditures in the first six months of 2018. Common dividend payments totaled $26.6 million in the first six months of 2018.

CAPITAL REQUIREMENTS

2019-2023 Capital Expenditures

Our consolidated capital expenditure plan for the 2019-2023 time period has been revised from $1.07 billion to $1.11 billion. The increase is primarily driven by the need for additional wind and technology-related investments and transmission investments. Given the increased capital expenditure plan, our compounded annual growth rate in rate base is projected to be 8.6% over the 2018 to 2023 timeframe.

The following table shows our 2018 capital expenditures and our currently anticipated 2019 through 2023 capital expenditures and electric utility average rate base.

(in millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Capital Expenditures:							
Electric Segment:							
Renewables and Natural Gas Generation		$ 125	$ 264	$ 15	$ 82	$ -	$ 486
Transformative Technology and Infrastructure		2	7	18	47	54	128
Transmission (*includes replacements*)		43	42	21	19	17	142
Other		43	45	58	49	55	250
Total Electric Segment	$ 87	$ 213	$ 358	$ 112	$ 197	$ 126	$ 1,006
Manufacturing and Plastics Segments	18	20	18	19	23	19	99
Total Capital Expenditures	**$ 105**	**$ 233**	**$ 376**	**$ 131**	**$ 220**	**$ 145**	**$ 1,105**
Total Electric Utility Rate Base	**$ 1,100**	**$ 1,176**	**$ 1,394**	**$ 1,531**	**$ 1,581**	**$ 1,665**	

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 2019 through 2023 timeframe.

Table of Contents

As of June 30, 2019, OTP had capitalized approximately $19.6 million in project costs and allowance for funds used during construction (AFUDC) associated with Astoria Station. OTP expects Astoria Station will cost approximately $158 million and be completed prior to the planned retirement of Hoot Lake Plant in May 2021. As of June 30, 2019, OTP had capitalized approximately $5.6 million in development costs and AFUDC associated with the Merricourt Wind Energy Center (Merricourt). OTP expects Merricourt will cost approximately $270 million and be completed in October 2020. For further details on these two projects see disclosures in Note 3 to our consolidated financial statements.

Contractual Obligations

In the first six months of 2019, OTP paid down approximately $13.5 million of its $64.5 million in obligations for commitments under contracts, including its share of construction program commitments and other nonlease commitments in place on December 31, 2018 and increased its commitments for the last six months of 2019 by $26.3 million. Also, in the second quarter of 2019 OTP’s lease payment obligations reported in Note 8 to the consolidated financial statements increased by $0.2 million as a result of OTP entering into a 27-month agreement for the lease of 20 additional coal rail cars to transport coal to Hoot Lake Plant from May 2019 through August 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 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 Plan expires on May 3, 2021.

Short-Term Debt

The following table presents the status of our lines of credit as of June 30, 2019 and December 31, 2018:

(in thousands)	Line Limit	In Use on June 30, 2019	Restricted due to Outstanding Letters of Credit	Available on June 30, 2019	Available on December 31, 2018
Otter Tail Corporation Credit Agreement	$ 130,000	$ 13,801	$ -	$ 116,199	$ 120,785
OTP Credit Agreement	170,000	22,801	8,766	138,433	160,316
Total	$ 300,000	$ 36,602	$ 8,766	$ 254,632	$ 281,101

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the OTC 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 OTC Credit Agreement. On October 31, 2018 the OTC Credit Agreement was amended to extend its expiration date by one year from October 31, 2022 to October 31, 2023. 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 OTC 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 OTC Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation 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 OTC Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial Covenants.” The OTC 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 OTC Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the OTC 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, 2018 the OTP Credit Agreement was amended to extend its expiration date by one year from October 31, 2022 to October 31, 2023. 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.

Both the OTC Credit Agreement and the OTP Credit Agreement currently expire on October 31, 2023. Borrowings under these agreements currently use LIBOR as the base to determine the applicable interest rate. LIBOR is currently expected to be eliminated by January 1, 2022. Both agreements contain a provision to determine how interest rates will be established in the event a replacement for LIBOR has not been identified before the agreement expires. The process calls for the parties to jointly agree on an alternate rate of interest to LIBOR, such as the Secured Overnight Financing Rate, that gives due consideration to prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time. The parties will enter into amendments to these agreements to reflect any alternate rate of interest and other related changes to the agreements as may be applicable. If for any reason an agreement cannot be reached on an alternate rate of interest, then any borrowings under the agreements will be determined using the Prime Rate plus a margin based on the Company’s and OTP’s long-term debt ratings at the time of the borrowings. If the alternate rate of interest agreed to by the parties is less than zero, such rate shall be deemed to be zero for the purposes of the credit agreement.

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.

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 a Term Loan Agreement.

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.

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 June 30, 2019.

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 OTC 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 June 30, 2019, our Interest and Dividend Coverage Ratio calculated under the requirements of the OTC Credit Agreement and the 2016 Note Purchase Agreement was 4.30 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 June 30, 2019, 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 3.34 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 June 30, 2019, our ratio of Interest-bearing Debt to Total Capitalization was 0.46 to 1.00 on a consolidated basis and 0.47 to 1.00 for OTP. Neither Otter Tail Corporation nor OTP had any Priority Indebtedness outstanding as of June 30, 2019.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $11.5 million, but our line of credit borrowing limits are only restricted by $8.8 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.

2019 BUSINESS OUTLOOK

We anticipate 2019 diluted earnings per share to be in the range of $2.10 to $2.25. We have taken into consideration strategies for improving future operating results, the cyclical nature of some of our businesses and current regulatory factors facing our Electric segment. We expect capital expenditures for 2019 to be $233 million compared with actual cash used for capital expenditures of $105 million in 2018. Our planned expenditures for 2019 include $79 million for Merricourt and $46 million for Astoria Station.

Segment components of our 2019 earnings per share guidance range compared with 2018 actual earnings are as follows:

Diluted Earnings Per Share	2018 EPS by Segment	2019 Guidance February 18, 2019		2019 Guidance May 6, 2019		2019 Guidance August 5, 2019	
		Low	High	Low	High	Low	High
Electric	$ 1.36	$ 1.46	$ 1.49	$ 1.48	$ 1.51	$ 1.48	$ 1.51
Manufacturing	$ 0.32	$ 0.37	$ 0.41	$ 0.35	$ 0.39	$ 0.33	$ 0.37
Plastics	$ 0.60	$ 0.44	$ 0.48	$ 0.44	$ 0.48	$ 0.46	$ 0.50
Corporate	$ (0.22)	$ (0.17)	$ (0.13)	$ (0.17)	$ (0.13)	$ (0.17)	$ (0.13)
Total	$ 2.06	$ 2.10	$ 2.25	$ 2.10	$ 2.25	$ 2.10	$ 2.25
Return on Equity	11.5%	11.5%	12.3%	11.5%	12.3%	11.5%	12.3%

The following items contribute to our earnings guidance for 2019.

- We expect 2019 Electric segment net income to be higher than 2018 segment net income based on:

  - o The business outlook assumes an annual net revenue increase of approximately $2.6 million from the full approval of our South Dakota rate case settlement on May 14, 2019. The settlement also allowed us to retain the impact of lower tax rates related to the TCJA from January 1, 2018 through October 17, 2018. This outcome favorably impacts 2019 earnings by approximately $0.02 per share.

  - o Increases in AFUDC for planned capital projects, including Merricourt, and increases in AFUDC and North Dakota Generation Cost Recovery Rider revenue related to Astoria Station. Both projects began construction in 2019.

  - o Increased revenues from completion of the Big Stone South–Ellendale project and additional transmission investments related to our South Dakota Transmission Reliability project.

  - o Decreased operating and maintenance expenses due to decreasing costs of pension, medical, workers compensation and retiree medical benefits. The decrease in pension costs is a result of an increase in the discount rate from 3.90% to 4.50%.

  - o Expenses incurred in the last half of 2018 that are not expected to occur during the last half of 2019 consisting of $3.2 million related to the Big Stone Plant outage and the contribution to the Otter Tail Power Company Foundation of $500,000.

  partially offset by:

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

  - o The extension of the planned outage at Coyote Station due to turbine rotor blade damage that was discovered in the early stages of the outage and the unplanned maintenance outage at Hoot Lake Plant, which both occurred in the second quarter of 2019.

Table of Contents

- We expect 2019 net income from our Manufacturing segment to increase over 2018. The overall increase in segment earnings in 2019 is based on:

  - o Increased sales at BTD driven by growth in the recreational vehicle, lawn and garden and agricultural end markets. Most of this growth is organic with our existing customer base. However, we are lowering both ends of the guidance range due to expected softness in scrap metal revenues based on lower scrap metal prices in the second quarter which we expect will remain low for the rest of the year, partially offset by higher scrap volumes.

  - o A decrease in earnings from T.O. Plastics mainly due to first quarter volume softness and the expected impact on business operations of the partial collapse and replacement of a warehouse roof, which was damaged in March of 2019 during a winter storm.

  - o Backlog for the manufacturing companies of approximately $115 million for 2019 compared with $107 million one year ago.

- We expect 2019 net income from the Plastics segment to be lower than 2018 based on lower expected operating margins in 2019. This is due to lower sales volumes in 2019 compared to 2018, slightly lower sales prices and higher resin prices, which have recently moderated. The increase in the guidance is driven by the expectation that resin prices will not be increasing as much as originally thought based on current market dynamics.

- Corporate costs, net of tax, are expected to be lower in 2019 than in 2018. In 2018, we incurred expenses of $2 million for a contribution to the Otter Tail Corporation Foundation and $1.2 million for accruals related to certain tax matters. These expenses are not expected to occur during the remainder of 2019.

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, 2018. There were no material changes in critical accounting policies or estimates during the six months ended June 30, 2019.

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, 2018, as well as the various factors described below:

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

- 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, 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 our businesses through capital projects, including infrastructure and new technology additions, or to grow or realign our businesses through acquisitions or 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 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.
- Our electric 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.
- Our electric transmission and generation facilities could be vulnerable to cyber and physical attack that could impair our ability to provide electrical service to our customers or disrupt the U.S. bulk power system.
- Our 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.
- Changes to regulation of generating plant emissions, including but not limited to carbon dioxide emissions and regional haze regulation under state implementation plans, could affect our operating costs and the costs of supplying electricity to our customers and the economic viability of

continued operation of certain of our steam-powered electric plants.

- Competition from foreign and domestic manufacturers, the price and availability of raw materials, trade policy and tariffs affecting prices and markets for raw material and manufactured products, 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 our plastics business.

- We compete against many 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 June 30, 2019 we had exposure to market risk associated with interest rates because we had $13.8 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.50% under the OTC Credit Agreement and OTP had $22.8 million in short-term debt outstanding on June 30, 2019 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 June 30, 2019 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 June 30, 2019, 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 June 30, 2019.

During the fiscal quarter ended June 30, 2019, 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.

PART II. OTHER INFORMATION

Item 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 28 through 35 of our Annual Report on Form 10-K for the year ended December 31, 2018.

Item 6. Exhibits

2.1	First Amendment to Asset Purchase Agreement and Turnkey Engineering, Procurement and Construction Services Agreement dated as of June 11, 2019, among Otter Tail Power Company, EDF Renewables Development, Inc., Power Partners Midwest, LLC, EDF-RE US Development, LLC, and Merricourt Power Partners, LLC.*
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.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Certain information has been omitted from this exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

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: August9, 2019

(Back To Top)

Section 2: EX-2.1 (EXHIBIT 2.1)

EXHIBIT 2.1

CERTAIN INFORMATION HAS BEEN OMITTED FROM THIS EXHIBIT PURSUANT TO ITEM 601(b)(2)(ii) OF REGULATION S-K BECAUSE IT IS NOT MATERIAL TO INVESTORS AND WOULD LIKELY CAUSE COMPETITIVE HARM TO THE REGISTRANT IF PUBLICLY DISCLOSED. OMISSIONS ARE DESIGNATED AS [**].

EXECUTION VERSION

FIRST AMENDMENT TO ASSET PURCHASE AGREEMENT AND TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION SERVICES AGREEMENT

THIS FIRST AMENDMENT TO ASSET PURCHASE AGREEMENT and TURNKEY ENGINEERING, PROCUREMENT AND CONSTRUCTION SERVICES AGREEMENT (“***Amendment***”) is dated as of June 11, 2019, by and between Otter Tail Power Company, a Minnesota corporation (“***Buyer***”), EDF Renewables Development, Inc., a Delaware corporation (f/k/a EDF Renewable Development, Inc.) (“***EDF-RD***”), Power Partners Midwest, LLC, a Delaware limited liability company (“***PPM***”), EDF-RE US Development, LLC, a Delaware limited liability company (“***EDF-USD***”), and Merricourt Power Partners, LLC, a Delaware limited liability company (“***Merricourt***”, and collectively with EDF-RD, PPM, and EDF-USD, the “***Sellers***”).

RECITALS

WHEREAS, Buyer and Sellers entered into that certain Asset Purchase Agreement on November 16, 2016 (the “***Agreement***”).

WHEREAS, Buyer and EDF-USD, entered into that certain Turnkey Engineering, Procurement and Construction Services Agreement (Merricourt Wind Project) on November 16, 2016 (the “***TEPC***”).

WHEREAS, the Parties wish to amend the Agreement to address the recent FERC approval of that certain Offer of Settlement and Settlement Agreement filed by MISO and Merricourt on October 11, 2018 associated with Merricourt’s MISO Interconnection Queue Request G359 and the subsequent withdrawal of MISO Interconnection Queue Request J457 on January 14, 2019.

WHEREAS, Buyer and Seller desire to enter into this Amendment in order to document their further agreement with respect to the Agreement and the TEPC.

NOW THEREFORE, in consideration of the foregoing and the terms and conditions set forth herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

AGREEMENTS:

A. Definitions

Unless otherwise defined in this Amendment, the terms used herein shall have the meanings as set forth in the Agreement.

B. Amendments to the Agreement.

The Parties hereby agree that the Agreement is amended as follows:

1. **New Definitions.** The following definitions shall be added to the Agreement in appropriate alphabetical order:

"***Applicable Limit***" shall mean, for any applicable dispatch interval, any MISO-imposed generation output limit applicable to the Project for such dispatch interval, whether such generation output limit is the QOL or any other MISO-imposed generation output limit applicable to the Project; *provided*, that generation output limits driven by LMP at the Project node shall not be an Applicable Limit.

"***CIA***" is defined in Section 6.10(c)(i).

"***Consent Notice***" shall mean written notice given not less than ten (10) Business Days (or such lesser time as may be applicable if a Proposal expires less than ten (10) Business Days after received from the relevant third party) prior to the expiration (if any expiration is specified) of any Proposal by the Consenting Party to the other Party or Parties that it would agree to a Proposal; *provided* that such Consent Notice shall include a copy of the Proposal.

"***Consenting Party***" is defined in Section 6.10(c)(iv).

"*FERC Approval*" shall mean the approval by FERC dated January 11, 2019 of the FERC G359 Settlement at 166 FERC ¶ 61,017 and filed in FERC Docket No. ER16-471-002.

"*FERC G359 Settlement*" shall mean that certain Offer of Settlement and Settlement Agreement filed by MISO and Merricourt on October 11, 2018 associated with Merricourt's MISO Interconnection Queue Request G359.

"*GIA Related Rights*" shall mean all rights in MISO Interconnection Queue Request G359R and all associated studies, reports and communications with MISO related thereto, including any associated facility construction agreements, multi-party facility construction agreements, or engineering and procurement agreements.

"*Interconnection Final Payment Date*" shall mean the last to occur of (a) December 31, 2021, (b) the date the final system upgrade costs (including Self-Funded Costs) for the GIA are known with respect to the system upgrades identified by MISO pursuant to the GIA, or (c) the date of [**].

"***J457 Withdrawal***" shall mean the termination and withdrawal of MISO Interconnection Queue Request J457 from MISO's interconnection process as of January 14, 2019.

"***MISO FERC Electric Tariff***" shall mean the MISO Open Access Transmission, Energy and Operating Reserves Markets Tariff.

[**] Denotes information that has been omitted from the exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

"***MISO Rules***" means the business practices, policies, rules, guidelines, procedures, protocols, standards, criteria and requirements promulgated and imposed by MISO, including the MISO FERC Electric Tariff.

"**Net Electric Energy**" is defined in Exhibit J.

"***Nonconsenting Party***" is defined in Section 6.10(c)(iv).

"***Other Amounts***" shall mean (a) any dollar amounts contractually committed or actually paid by Sellers or Buyer after January 1, 2019 in respect of Other Claims, *provided* such amounts have been mutually reviewed and agreed upon by Sellers and Buyer pursuant to Section 6.10(c), and (b) any reasonable and documented legal fees of a single outside counsel selected by the Party controlling the resolution of an Other Claim, and any reasonable costs and expenses incurred by such counsel.

"***Other Claim(s)***" shall mean one or more third party claims asserted or threatened in writing on or prior to December 31, 2021 [**] or involving financial or regulatory impacts asserted to directly result from the implementation of one or more of the above.

"***Point of Interconnection***" shall have the meaning ascribed to it in the GIA.

"***Proposal***" shall mean a written settlement proposal (via email or other written correspondence) from a third party proposing to resolve all litigation or claims related to its Other Claim.

"***QOL***" means the maximum permissible output of the Project until all upgrades listed in the GIA are completed, updated on a quarterly basis, and determined by the process described in Section 7 of MISO's Generation Interconnection Business Practice Manual titled "Limited Operation", or its successor.

"***Required Upgrades***" is defined in Section 6.18.

"***Self-Funded Costs***" shall mean actual costs expended for the transmission upgrades required to be constructed pursuant to the GIA and the GIA Related Rights which the applicable transmission owner has elected to fund itself and which will be assessed against the Project through the MISO FERC Electric Tariff. For the avoidance of doubt, Self-Funded Costs shall not include any interest or return on investment available through the MISO FERC Electric Tariff and associated with the transmission upgrade costs.

"***Test Plan***" means the plan for testing the WTGs, as set forth in the Pre-Commercial Generation Test Notification Form (provided in Appendix D of MISO's Generation Interconnection Business Practice Manual) to be submitted to MISO's real time operations no later than five (5) Business Days prior to any testing of a WTG at the Project.

2. **Amended Definitions.** The following definitions shall be amended and restated in their respective entireties as follows:

[**] Denotes information that has been omitted from the exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

“***Final Order***” means a final order of a Governmental Authority of competent jurisdiction, (i) from which there is no right to request rehearing or to appeal to any other Governmental Authority or (ii) with respect to which either (A) all applicable time periods during which a request for rehearing or an appeal may be made have expired or (B) no appeal has been made within a period of two months from issuance of an appealable order, whichever is the earliest to occur.

“***GIA***” means the Generator Interconnection Agreement dated as of March 6, 2019, by and between EDF-RD, Montana-Dakota Utilities Co. and MISO for MISO Interconnection Queue Request G359R, as amended, supplemented, restated or otherwise modified from time to time.

“***GIA Delay Damages***” is defined in Exhibit J.

“***Interconnection Costs***” means (a) the network upgrade costs under the GIA and the GIA Related Rights, including Self-Funded Costs and any increased costs incurred by a transmission owner to accelerate completion of system upgrades, *plus* (b) any Other Amounts.

“***Outside Date***” means July 15, 2019.

“***Third Party Claim***” means any Action by a third party which is not an Other Claim.

3. Definitions. The following definitions shall be deleted in their entirety:

“***ERIS Interconnection Costs***”, “***Estimated Interconnection Costs***”, “***Excess Interconnection Costs***”, **“*Interconnection Notice*”,** “***Network Integration Transmission Service***”, “***Network Resource Interconnection Service***”, “***New GIA***”, and “***NRIS Interconnection Costs***”.

4. Purchased Price. Section 2.5(a) of the Agreement will be amended and restated in its entirety as follows:

(a) The purchase price (the “***Purchase Price***”) for the purchase and sale described in Section 2.1 is equal to $37,682,118.

5. Purchased Assets. Section 2.1(d) of the Agreement will be amended and restated in its entirety as follows:

(d) the Purchased Contracts, including the GIA and the GIA Related Rights;

6. Assumed Liabilities. Sections 2.3(b) and (c) of the Agreement will be amended and restated in their respective entireties as follows:

(b) those obligations of Sellers accruing or arising, or covenants or agreements of Sellers to be performed (other than indemnification obligations for matters accruing or arising prior to the Closing Date), from and after the Closing Date under the Land

Contracts, Purchased Contracts (other than the GIA, GIA Related Rights and the COD Purchased Contracts), Permits, and Permit applications;

(c) Buyer's portion of the costs associated with the GIA and GIA Related Rights as set forth in Section 6.10;

7. Excluded Liabilities. Sections 2.4(e) and (g) of the Agreement will be amended and restated in their respective entireties as follows:

(e) any Liability under the Land Contracts, Purchased Contracts (other than the GIA and GIA Related Rights), Permits or Permit applications to the extent such Liability, but for a breach or default by Sellers or a waiver or extension given to or by Sellers, would have been paid, performed or otherwise discharged on or prior to the Closing Date or to the extent such Liability arises out of any such breach, default, waiver or extension given to or by Sellers;

(g) Sellers' portion of the costs associated with the GIA and GIA Related Rights as set forth in Section 6.10 and except to the extent they are [**] all costs associated with MISO Interconnection Queue Request J457;

8. Closing. Section 3.1 of the Agreement will be amended and restated in its entirety as follows:

Section 3.1 **Closing**. The Closing will take place at the offices of Dorsey & Whitney LLP, 50 South Sixth Street, Suite 1500, Minneapolis, Minnesota, or by remote electronic exchange of documents (by facsimile, .pdf, e-mail, or other form of electronic communication) on the later to occur of (a) July 3, 2018 and (b) a mutually acceptable date within fifteen (15) days after satisfaction of all closing conditions or at such other time, place and date as the Parties may agree in writing. All actions listed in Section 3.2 or Section 3.3 that occur on the Closing Date will be deemed to occur simultaneously at the Closing. The Closing will be deemed to be effective as of 11:59:59 p.m. Central Time on the Closing Date.

9. Interconnection. Section 6.10 of the Agreement will be amended and restated in its entirety as follows:

Section 6.10 Interconnection.

(a) Interconnection Cooperation. The Parties hereby agree to cooperate in good faith to evaluate interconnection studies and share information related to the timing and costs of the Project interconnection. Without limiting the generality of the foregoing, Sellers shall (i) promptly upon receipt thereof, provide copies of all studies and other communications received from MISO or any other RTO or transmission owner with respect to MISO Interconnection Queue Request G359R; (ii) promptly provide Buyer with copies of all drafts of generator interconnection agreements, facility construction agreements multi party facility construction agreements and engineering and procurement agreements received from MISO

[**] Denotes information that has been omitted from the exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

or the applicable transmission owner prior to Closing; (iii) provide Buyer a period of not less than ten (10) days following Buyer's receipt from Sellers of copies of such draft documents to review and comment on such draft documents; and (iv) allow and facilitate Buyer participation in any telephone calls or negotiating sessions regarding the same.

(b) Interconnection Costs.

(i) The responsibility for the Interconnection Costs shall be as follows:

(A) Buyer shall be responsible for all Interconnection Costs up to the base cost of [**].

(B) If the Interconnection Costs are between [**] and [**], responsibility for such incremental costs shall be borne one-half by Buyer and one-half by Sellers.

(C) Sellers shall be responsible for all Interconnection Costs in excess of [**] but less than [**].

(D) If the Interconnection Costs are between [**] and [**], responsibility for such incremental costs shall be borne one-half by Buyer and one-half by Sellers

(E) If after Closing, actual Interconnection Costs exceed an amount equal to [**] then Buyer will be responsible for the amount of such excess.

(F) For the avoidance of doubt, Sellers shall bear full responsibility for all costs and expenses associated with the Existing GIA and all costs and expenses related to the MISO Interconnection Queue Request G359 except as expressly set forth in the definition of the term Interconnection Costs.

(ii) Payments of Interconnection Costs shall be settled as follows:

(A) Buyer shall replace any letter of credit previously delivered by Sellers to MISO or a transmission owner to secure any Interconnection Costs (if applicable) and request any such previous letter of credit to be released by MISO or such transmission owner within two Business Days of the Closing.

(B) During the period from the Closing Date to the Interconnection Final Payment Date, at the time that any payment of Interconnection Costs is due, either (I) such payment shall be made pro rata by Sellers on the one hand and Buyer on the other in accordance with their respective responsibility for such amount, or

[**] Denotes information that has been omitted from the exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

(II) if one Party pays, or is deemed to have paid in accordance with Section 6.10(b)(ii)(C) below, any amount that is the responsibility of another party, the responsible Party shall promptly reimburse the amount of such payment plus interest thereon at the Interest Rate commencing ten (10) Business Days after the later of the date the Party making the payment makes such payment or the date the responsible Party is notified of its obligation to reimburse such amount.

(C) The aggregate amount of each Other Claim which is allocated between Sellers on the one hand and Buyer on the other pursuant to Section 6.10(c)(iv) shall be [**], but the allocation of such amounts shall be pursuant to Section 6.10(c)(iv). Buyer shall be deemed to have paid the Self-Funded Costs on the Closing Date, *provided*, that no true-up of such costs shall be made until such costs are final.

(D) Following the Commercial Operation Date, Buyer shall (1) bear any new interconnection costs in addition to those known and allocated between the parties before such date and (2) be entitled to receive 100% of any refunds related to the GIA that aren't known as of the Commercial Operation Date. For the avoidance of doubt, the Parties acknowledge that "new interconnection costs" refers to costs associated with system upgrades not specifically known about as of the Commercial Operation Date and not changes in amounts of Interconnection Costs.

(E) Sellers shall be entitled to any refunds related to the J457 Withdrawal and except to the extent they are [**] shall be responsible for all costs associated with MISO Interconnection Queue Request J457.

(c) Settlement of Other Claims.

(i) No Other Claim shall be settled or any Proposal agreed to without the consent and agreement of Sellers and Buyer. To this end, Sellers and Buyer have entered into that certain Common Interest Information Sharing and Confidentiality Agreement effective as of April 9, 2019 (the "***CIA***").

(ii) Prior to the Closing Date, Sellers shall control and lead the defense of all Other Claims and all settlement discussions related to such Other Claims; *provided*, that Sellers shall keep Buyer fully informed of developments in connection with such Other Claims (including all communications related to such Other Claims), shall consult with Buyer with respect to addressing such Other Claims and shall invite Buyer to join any settlement discussions with the third party claimants bringing such Other Claims. Sellers shall not make any settlement proposal without the

[**] Denotes information that has been omitted from the exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

prior consent of Buyer (such consent not to be unreasonably withheld, conditioned or delayed) and following the Closing Date Sellers shall refer all third party claimants bringing Other Claims to Buyer.

(iii) Following the Closing Date, Buyer shall control and lead the defense of all Other Claims and all settlement discussions related to such Other Claims; *provided*, that Buyer shall keep Sellers fully informed of developments in connection with such Other Claims (including all communications related to such Other Claims), shall consult with Sellers with respect to addressing such Other Claims and shall invite Sellers to join any settlement discussions with the third party claimants bringing such Other Claims. Buyer shall not make any settlement proposal without the prior consent of Sellers (such consent not to be unreasonably withheld, conditioned or delayed) and prior to the Closing Date Buyer shall refer all third party claimants bringing Other Claims to Sellers.

(iv) If one Party (the "***Consenting Party***") delivers a Consent Notice to the other Party and the other Party (the "***Nonconsenting Party***") objects to the Proposal by written notice to the Consenting Party stating its reasons for objection within five (5) Business Days of receipt of the Consent Notice, the liability of the Consenting Party with respect to such Other Claim will be equal to the lesser of (A) its proportionate share of such Proposal (including its proportionate share of legal costs included in clause (b) of the definition of "Other Amounts") and (B) the final total cost (including all legal costs included in clause (b) of the definition of "Other Amounts") associated with such Other Claim (as provided in a settlement agreement or pursuant to a Final Order). If the Party (or Parties) receiving a Consent Notice fails to respond within the five (5) Business Day period either consenting or objecting to the Proposal, such Party shall be deemed to be a Nonconsenting Party. The Nonconsenting Party shall be liable for the balance, if any, of such final total costs notwithstanding any otherwise applicable limits in Section 6.10(b)(i). If at the time of such Proposal the Consenting Party is controlling the defense of the Other Claim, the Nonconsenting Party shall have the right to take over control of the defense of the Other Claim.

(d) SPS Plan. Prior to the Closing Date, Sellers shall reasonably cooperate with Buyer in connection with seeking and developing an adequate special protection system for the Project.

10. Additional Covenants. ARTICLE 6 of the Agreement will be amended by adding the following new Sections 6.17 and 6.18 to the end thereof:

Section 6.17 Maximizing Dispatch and Forecasting. During the period beginning with the first generation of test energy for the Project and continuing until June 1, 2022, Buyer and Sellers will cooperate with respect to, and Buyer shall take, all scheduling, planning, bidding, offering, day ahead forecasting, and other actions in each case necessary or advisable in connection with the MISO Rules, and other applicable rules and the nodal market (or any replacement thereof) to ensure that the Project is fully dispatched and that all electrical energy the Project is capable of generating (net of station load and electrical losses up to the Point of Interconnection) will be received at and delivered to the Point of Interconnection. Buyer shall prepare day ahead forecasts and updates by utilizing a wind speed and direction prediction model or service that is (a) commercially available to Buyer or an Affiliate of Buyer, and (b) comparable in accuracy to models or services commonly used in the wind energy industry and that reflect WTG availability, so long as such model or service is available at a commercially reasonable cost. [**].

Section 6.18 GIA Delay Damages. Without limiting Buyer's other rights under this Agreement, during the following periods, Seller is obligated to pay to Buyer GIA Delay Damages calculated as follows:

(a) from the beginning of "Trial Operation" (as defined in the GIA) of the Project and continuing until energization of network upgrades (other than network upgrades on facilities owned by Buyer) listed in Exhibit A5 of the GIA (the "***Required Upgrades***"), if the commissioned nameplate capacity of the Project is higher than the Applicable Limit, then, for each applicable MISO dispatch interval during which the Net Electric Energy is equal to or within 4MW of the Applicable Limit, Buyer shall calculate the amount of GIA Delay Damages (if any) associated with that applicable MISO dispatch interval in accordance with the provisions of this Section 6.18 and Exhibit J; and

(b) from energization of the Required Upgrades until June 1, 2022, if the commissioned nameplate capacity of the Project is higher than the QOL, then, for each applicable MISO dispatch interval during which the Net Electric Energy is equal to or within 4MW of the QOL, Buyer shall calculate the amount of GIA Delay Damages (if any) associated with that applicable MISO dispatch interval in accordance with the provisions of this Section 6.18 and Exhibit J. For the avoidance of doubt, if the Required Upgrades are energized before a QOL is applicable to the Project, no GIA Delay Damages shall apply following energization of the Required Upgrades until a QOL is applicable to the Project.

(c) Buyer will deliver to Sellers within ten (10) Business Days after the end of each month where GIA Delay Damages have been incurred, an invoice accompanied by Buyer's calculation of the GIA Delay Damages for the preceding month, plus any additional backup information reasonably requested by Sellers. Sellers shall be required to pay to Buyer the undisputed amount of GIA Delay Damages for the preceding month within five (5) Business Days of their receipt of Buyer's invoice, calculation and any additional backup information reasonably requested for the preceding month's GIA Delay Damages; *provided*, that the aggregate amount of all monthly payments of GIA Delay Damages shall not exceed $6,000,000. Any dispute regarding the amount of GIA Delay Damages payable for any given month shall be

[**] Denotes information that has been omitted from the exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

resolved in accordance with the procedures set forth in Exhibit J for resolution of such disputes.

(d) From and after Closing, Buyer shall comply with all of its obligations under the GIA and GIA Related Rights (other than the obligations which are the responsibility of the Contractor (as defined in the TEPC) pursuant to Section 2.17 of the TEPC) and shall use commercially reasonable efforts to make the Transmission Owner and Transmission Provider (as each such term is defined in the GIA) and counterparties to any contracts included in GIA Related Rights comply with their respective obligations thereunder.

11. Closing Conditions.

a. Section 7.1 of the Agreement shall be amended by adding the following new clause (c) to the end thereof:

(c) The Parties shall have agreed to the calculation methodology for determining Potential Production (as defined in Exhibit J).

b. Section 7.2(t) of the Agreement shall be amended and restated in its entirety as follows:

(t) The GIA shall have been executed and shall be effective under the Federal Power Act, as provided in Section 3.5 of the FERC G359 Settlement; *provided*, that in the event the GIA is filed at FERC through an Electronic Quarterly Report, for purposes of this Agreement, the GIA shall be deemed to be effective under the Federal Power Act on the date such Electronic Quarterly Report is accepted for filing by FERC;

c. Section 7.2 of the Agreement shall be further amended by adding the following new clause (z) to the end thereof.

(z) the FERC Approval shall be a Final Order or shall have been confirmed by a Final Order;

12. GIA Delay Damages. Section 8.1(d) shall be deleted in its entirety and the following shall be substituted therefor:

(d) [Reserved.]

13. Automatic Termination. Section 8.1(j) shall be deleted in its entirety and the following shall be substituted therefor:

(j) [Reserved.]

14. Consequential Damages. Section 9.4(h) shall be deleted in its entirety and the following shall be substituted therefor:

(h) **EXCEPT IN THE CASE OF GIA DELAY DAMAGES, AN OTHER CLAIM [**], AND AN INDEMNITY CLAIM UNDER SECTION 9.2(C), IN NO EVENT SHALL EITHER PARTY BE LIABLE FOR ANY LOST OR PROSPECTIVE PROFITS NOR ANY PUNITIVE, EXEMPLARY, CONSEQUENTIAL, INCIDENTAL OR INDIRECT LOSSES OR DAMAGES (IN TORT, CONTRACT OR OTHERWISE) UNDER OR IN RESPECT TO THIS AGREEMENT, OTHER THAN SUCH DAMAGES THAT ARISE OUT OF A CLAIM MADE BY A THIRD PARTY AGAINST BUYER OR SELLERS, AS APPLICABLE.**

15. Third Party Claims. Section 9.5(a) shall be deleted in its entirety and the following shall be substituted therefor:

(a) Promptly after receipt by an Indemnified Party of notice of the commencement of any Third Party Claim with respect to any matter for which indemnification is or may be owing pursuant to Section 9.2 or 9.3 hereof, the Indemnified Party will give notice thereof to the Indemnifying Party, provided, however, that the failure of the Indemnified Party to notify the Indemnifying Party will not relieve the Indemnifying Party of any of its obligations hereunder, except to the extent that the Indemnifying Party demonstrates that the defense of such Third Party Claim has been actually prejudiced by the Indemnified Party's failure to give such notice.

16. Exhibit J. The Agreement will be amended by adding a new Exhibit J to the Agreement in the form of Exhibit J attached hereto.

17. Schedule 4.9. Schedule 4.3(a) of the Agreement is amended by deleting item 1 in its entirety and Schedule 4.9 of the Agreement is amended by deleting item 1 under "Purchased Contracts" in its entirety and in each case replacing such deleted item with the following:

1. Generator Interconnection Agreement dated as of March 6, 2019, by and between EDF-RD, Montana-Dakota Utilities Co. and MISO for MISO Interconnection Queue Request G359R, as amended, supplemented, restated or otherwise modified from time to time, together with the GIA Related Rights.

C. <u>TEPC Amendments</u>

1. **Amended Definitions**. Each of the following definitions set forth in Section 1.1 of the TEPC is amended and restated in its entirety as follows:

"***Guaranteed Project Substantial Completion Date***" means October 31, 2020, as modified in accordance with Section 5.5 and Article 9.

"***Guaranteed Mechanical Completion Date***" means September 30, 2020, as

[**] Denotes information that has been omitted from the exhibit pursuant to Item 601(b)(2)(ii) of Regulation S-K.

modified in accordance with Section 5.5 and Article 9.

"***Interconnection Agreement***" means the GIA and the GIA Related Rights, as each such term is as defined in the Asset Purchase Agreement.

2. **New Definitions**. The following definition shall be added to Section 1.1 of the TEPC in appropriate alphabetical order

"***Outside Date***" has the meaning given to such term in the Asset Purchase Agreement.

3. **Interconnection**. Section 2.17 of the TEPC is hereby amended by adding the following to the end thereof: "Without limiting the generality of the foregoing, Contractor shall provide a draft Test Plan (as such term is defined in the Asset Purchase Agreement) to Owner no later than 10 Business Days prior to the initial testing of any WTG.

D. <u>Other Terms</u>

1. This Amendment, and all claims or causes of action (whether in contract or tort) that may be based upon, arise out of or relate to this Amendment, or the negotiation, execution or performance of this Amendment (including any claim or cause of action based upon, arising out of or related to any representation or warranty made in or in connection with this Amendment or as an inducement to enter into this Amendment), will be governed by the laws of the State of New York without giving effect to any conflict or choice of law provision.

2. This Amendment may be executed in any number of counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument. Any facsimile or portable document format (pdf) copies hereof or signature hereon will, for all purposes, be deemed originals.

3. The Agreement, as modified by this Amendment, remains in effect in accordance with its terms. If there is any conflict between the Agreement and this Amendment, this Amendment shall control.

4. Except for the Confidentiality Agreement, the Agreement (as modified by this Amendment), the TEPC (as modified by this Amendment), the CIA and the Ancillary Agreements supersede all prior discussions and agreements between the Parties with respect to the subject matter hereof and thereof, and the Agreement, the TEPC, the Ancillary Agreements, the CIA, the Confidentiality Agreement and the other documents delivered pursuant to this Agreement (each as modified by this Amendment) contain the sole and entire agreement between the Parties hereto with respect to the subject matter hereof and thereof.

[Signature Pages to Follow]

IN WITNESS HEREOF, the Parties have caused this Amendment to be executed by their duly authorized representatives as of the date and year first above written.

BUYER:
OTTER TAIL POWER COMPANY,
a Minnesota corporation

By: /s/ Timothy J. Rogelstad
Name: Timothy J. Rogelstad
Title: President

SELLERS:
EDF RENEWABLES DEVELOPMENT, INC.,
a Delaware corporation

By: /s/ Tristan Grimbert
Name: Tristan Grimbert
Title: President & CEO

POWER PARTNERS MIDWEST, LLC,
a Delaware limited liability company

By: EDF Renewables, Inc., its Manager

By: /s/ Tristan Grimbert
Name: Tristan Grimbert
Title: President & CEO

EDF-RE US DEVELOPMENT, LLC,
a Delaware limited liability company

By: EDF Renewables Development, Inc., its Managing Member

By: /s/ Tristan Grimbert
Name: Tristan Grimbert
Title: President & CEO

MERRICOURT POWER PARTNERS, LLC,
a Delaware limited liability company

By: EDF-RE US Development, LLC, its Manager

By: EDF Renewables Development, Inc., its Managing Member

By: /s/ Tristan Grimbert
Name: Tristan Grimbert
Title: President & CEO

Exhibit J: Foregone Energy

Buyer shall use Prudent Industry Practice to calculate Foregone Energy in accordance with Section 6.18.

"**Dispatch Limit Production**" means the amount of Net Electric Energy the Project actually generated during any applicable MISO dispatch interval.

"**Forced Outage**" means any unscheduled and involuntary condition at the Project that requires immediate removal of the Project, or some material part thereof, from service. This type of outage results from immediate mechanical/electrical/hydraulic control system trips and operator-initiated trips in response to Project conditions and/or alarms.

"**Foregone Energy**" = the greater of (a) zero or (b) Potential Production – Dispatch Limit Production.

"**GIA Delay Damages**" means, for any applicable MISO 5- minute or 15-minute dispatch interval (or any successor thereto), an aggregate amount of liquidated damages incurred during such period, calculated separately for each day during such period as an amount equal to the greater of (a) $0 or (b)(i) $37, multiplied by (ii) the Foregone Energy as measured in MWhours.

"**Net Electric Energy**" means, at any time, one hundred percent (100%) of the electric energy generated by the Project by means of wind generation delivered to the Point of Interconnection. For clarity, Net Electric Energy shall not include electric energy used in the operation of the Project or electrical losses up to the Point of Interconnection.

"**Planned Outage**" means the removal of the Project or any portion thereof from service to perform work on specific components that will result in an interruption or reduction in delivery of Net Electric Energy to the Point of Interconnection (e.g., for repairs, inspections or testing).

"**Potential Production**" means the amount of Net Electric Energy the Project could potentially generate during any applicable MISO dispatch interval. The calculation methodology for "Potential Production" will be provided by AWS Truepower ("***Consultant***"), and will reflect industry best practices for calculating expected Net Electric Energy from the WTGs. The calculation methodology will be provided by Consultant prior to Closing, and will be automatically incorporated by reference into the end of this Exhibit J following final mutual agreement by the Parties (which may for purposes of this Agreement be satisfied via email communications) regarding the acceptability of the calculation methodology. Consultant shall be engaged by both Sellers and Buyer. Sellers shall pay the fees, costs and expenses of Consultant in connection with the development of the calculation methodology for Potential Production.

Potential Production shall be reduced by the amount of any energy that is not delivered to the Point of Interconnection for any of the following reasons that may be affecting individual WTGs or other equipment in the Project or the Project as a whole:

(a) an "Emergency Condition" (as defined in the GIA) or an "Emergency" (as defined in the MISO FERC Electric Tariff),

(b) following completion of the Required Upgrades, manual reliability curtailments initiated by MISO or the Transmission Owner (as defined in the GIA),

(c) after the Project Substantial Completion Date, any defect or damage to any Purchased Assets, so long as such defect or damage was not caused by the Sellers;

(d) after the Project Substantial Completion Date, the failure of "Interconnection Customer's Interconnection Facilities" (as defined in the GIA), due to Buyer's failure to maintain Interconnection Customer's Interconnection Facilities and other facilities in accordance with Prudent Industry Practices,

(e) a "Force Majeure Event" (as defined in the TEPC) or an event of "Force Majeure" (as defined in the GIA),

(f) a Forced Outage or Planned Outage,

(g) Buyer's breach or default under the TEPC, the Permits, Land Contracts or Purchased Contracts, including the GIA, or

(h) Buyer's failure to maintain in full force and effect any permit, consent, license, approval, or authorization from any Governmental Authority required by Law to operate the Project.

Foregone Energy, pursuant to the above formula, will be the sum of all of the Foregone Energy during the applicable MISO dispatch interval during the periods entitling Buyer to payment for GIA Delay Damages pursuant to Section 6.18.

Dispute Resolution. If there is any dispute regarding the amount of GIA Delay Damages payable in any month, Sellers must either notify Buyer in writing of such dispute on or before the due date for the payment of such amount and timely pay the undisputed amount or pay the entire amount invoiced by Buyer and within thirty (30) days following such timely payment provide Buyer written notice of such dispute. Following receipt of such notice, Buyer and Sellers shall in good faith attempt to resolve such dispute. If the Parties have not resolved such dispute within ten (10) days of the date of Sellers' notice, either Party may refer such dispute to Consultant who shall determine the amount of GIA Delay Damages. Consultant shall determine such GIA Delay Damages within five (5) Business Days of the referral of such dispute to Consultant for resolution. The Party required to make a payment by such Consultant shall pay (a) the amount due plus interest calculated at the Prime Rate as reported in the Wall Street Journal and (b) all costs, fees and expenses of Consultant associated with the determination of such disputed GIA Delay Damages.

(Back To Top)

Section 3: EX-31.1 (EXHIBIT 31.1)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Charles S. MacFarlane, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15 (f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial

reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 9, 2019

/s/ Charles S. MacFarlane
Charles S. MacFarlane
President and Chief Executive Officer
(Back To Top)

Section 4: EX-31.2 (EXHIBIT 31.2)

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kevin G. Moug, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 9, 2019

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Senior Vice President
(Back To Top)

Section 5: EX-32.1 (EXHIBIT 32.1)

Exhibit 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Otter Tail Corporation (the "Company") on Form 10-Q for the period ended June 30, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charles S. MacFarlane, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Charles S. MacFarlane
Charles S. MacFarlane
President and Chief Executive Officer
August 9, 2019

(Back To Top)

Section 6: EX-32.2 (EXHIBIT 32.2)

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Otter Tail Corporation (the "Company") on Form 10-Q for the period ended June 30, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kevin G. Moug, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Senior Vice President
August 9, 2019

(Back To Top)