Otter Tail Corp
Form 10-K
February 22, 2019

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

(**X**) Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2018**

( ) 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 (State or other jurisdiction of incorporation or organization)	**27-0383995** (I.R.S. Employer Identification No.)
215 SOUTH CASCADE STREET, BOX 496, FERGUS FALLS, MINNESOTA (Address of principal executive offices)	**56538-0496** (Zip Code)

Registrant's telephone number, including area code: **866-410-8780**

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

Title of each class	Name of each exchange on which registered
COMMON SHARES, par value $5.00 per share	**The Nasdaq Stock Market LLC**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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. (Check one):

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 in Rule 12b-2 of the Exchange Act).   Yes   No

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 29, 2018 was **$1,810,041,170.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **39,729,708 Common Shares ($5 par value) as of February 15, 2019.**

Documents Incorporated by Reference:

Proxy Statement for the 2019 Annual Meeting-Portions incorporated by reference into Part III

OTTER TAIL CORPORATION

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Definitions

The following abbreviations or acronyms are used in the text. References in this report to “the Company”, “we”, “us” and “our” are to Otter Tail Corporation.

2018 Notes	February 2018 issuance of $100 million in privately placed 4.07% Senior Unsecured Notes due February 7, 2048
ACE	Affodable Clean Energy
ADP	Advance Determination of Prudence
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AQCS	Air Quality Control System
ARO	Accumulated Asset Retirement Obligation
ASC	Accounting Standards Codification
ASC 606	ASC Topic 606 – *Revenue from Contracts with Customers*
ASC 715	ASC Topic 715 – *Compensation—Retirement Benefits*
ASC 718	ASC Topic 718 – *Compensation—Stock Compensation*
ASC 820	ASC Topic 820 – *Fair Value Measurement*
ASC 980	ASC Topic 980 – *Regulated Operations*
ASM	Ancillary Services Market
ASU	Accounting Standards Update
BTD	BTD Manufacturing, Inc.
CAA	Clean Air Act
CCMC	Coyote Creek Mining Company, L.L.C.
CCR	Coal Combustion Residuals
CIP	Conservation Improvement Program
CO2	carbon dioxide
CON	Certificate of Need
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction Work in Progress
D.C. Circuit	United States Court of Appeals for the District of Columbia
DRR	Data Requirement Rule
ECR	Environmental Cost Recovery
EDF	EDF Renewable Development, Inc.
EEI	Edison Electric Institute
EEP	Energy Efficiency Plan
EPA	Environmental Protection Agency
ESSRP	Executive Survivor and Supplemental Retirement Plan
Exchange Act	The Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FCA	Fuel Clause Adjustment

FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
Impulse	Impulse Manufacturing, Inc.
IRP	Integrated Resource Plan
JPMS	J.P. Morgan Securities LLC
kV	kiloVolt
kW	kiloWatt
kwh	kilowatt-hour
LSA	Lignite Sales Agreement
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MISO Tariff	MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff
MNCIP	Minnesota Conservation Improvement Program
MNDOC	Minnesota Department of Commerce
MPCA	Minnesota Pollution Control Agency
MPU Act	The Minnesota Public Utilities Act
MPUC	Minnesota Public Utilities Commission
MRO	Midwest Reliability Organization

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MVP	Multi-Value Project
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NAEMA	North American Energy Marketers Association
NDPSC	North Dakota Public Service Commission
NDRRA	North Dakota Renewable Resource Adjustment
NERC	North American Electric Reliability Corporation
NETOs	New England Transmission Owners
NPDES	National Pollutant Discharge Elimination System
Northern Pipe	Northern Pipe Products, Inc.
NOx	nitrogen oxide
NSPS	New Source Performance Standards
OTP	Otter Tail Power Company
PACE	Partnership in Assisting Community Expansion
ppb	parts per billion
PSD	Prevention of Significant Deterioration
PTCs	Production tax credits
PVC	Polyvinyl chloride
ROE	Return on equity
RTO Adder	Incentive of additional 50-basis points for Regional Transmission Organization participation
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
SF6	sulfur hexaflouride
SO2	sulfur dioxide
SPP	Southwest Power Pool
SRECs	Solar renewable energy credits
Standex	Standex International Corporation
T.O. Plastics	T.O. Plastics, Inc.
TCR	Transmission Cost Recovery
TCJA	2017 Tax Cuts and Jobs Act
Varistar	Varistar Corporation
VIE	Variable Interest Entity
Vinyltech	Vinyltech Corporation
WIIN	Water Infrastructure Improvements for the Nation

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PART I

Item 1. BUSINESS

(a) General Development of Business

Otter Tail Power Company was incorporated in 1907 under the laws of the State of Minnesota. In 2001, the name was changed to "Otter Tail Corporation" to more accurately represent the broader scope of consolidated operations and the name Otter Tail Power Company (OTP) was retained for use by the electric utility. On July 1, 2009 Otter Tail Corporation completed a holding company reorganization whereby OTP, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (the Company). The new parent holding company was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization. The Company's executive offices are located at 215 South Cascade Street, P.O. Box 496, Fergus Falls, Minnesota 56538-0496 and 4150 19th Avenue South, Suite 101, P.O. Box 9156, Fargo, North Dakota 58106-9156. The Company's telephone number is (866) 410-8780.

The Company makes available free of charge at its website (www.ottertail.com) its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Forms 3, 4 and 5 filed on behalf of directors and executive officers and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). These reports are also available on the SEC's website (www.sec.gov). Information on the Company's and the SEC's websites is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

Otter Tail Corporation and its subsidiaries conduct business primarily in the United States. The Company had approximately 2,321 full-time employees at December 31, 2018. The Company's businesses have been classified in three segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision maker. The three segments are Electric, Manufacturing and Plastics.

The chart below indicates the companies included in each of the Company's reporting segments.

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

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

Plastics consists of businesses producing polyvinyl chloride (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. The Company's manufacturing and plastic pipe businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar). The Company's corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance that are not allocated to its subsidiary companies. 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.

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The Company maintains a moderate risk profile by investing in rate base growth opportunities in its Electric segment and organic growth opportunities in its manufacturing platform, which includes its Manufacturing and Plastics segments. This strategy and risk profile is designed to provide a more predictable earnings stream, maintain the Company’s credit quality and preserve its ability to fund the dividend. The Company’s goal is to deliver annual growth in earnings per share between five to seven percent over the next several years, using 2018 diluted earnings per share as the base for measurement. The growth is expected to come from the substantial increase in the Company’s regulated utility rate base and from planned increased earnings from existing capacity in place at the Company’s manufacturing and plastic pipe businesses. The Company will continue to review its business portfolio to see where additional opportunities exist to improve its risk profile, improve credit metrics and generate additional sources of cash to support the growth opportunities in its electric utility. The Company will also evaluate opportunities to allocate capital to potential acquisitions in its Manufacturing and Plastics segments. Over time, the Company expects the electric utility business will provide approximately 75% to 85% of its overall earnings. The Company expects its manufacturing and plastic pipe businesses will provide 15% to 25% of its earnings and continue to be a fundamental part of its strategy. The actual mix of earnings in 2018 was 66% from the electric utility and 34% from the manufacturing and plastic pipe businesses, including unallocated corporate costs.

The Company maintains criteria in evaluating whether its operating companies are a strategic fit. The operating company should:

- Maintain a threshold level of net earnings and a return on invested capital in excess of the Company’s weighted average cost of capital.
- Have a strategic differentiation from competitors and a sustainable cost advantage.
- Operate within a stable and growing industry and be able to quickly adapt to changing economic cycles.
- Have a strong management team committed to operational and commercial excellence.

For a discussion of the Company's results of operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations," on pages 39 through 60 of this Annual Report on Form 10-K.

(b) Financial Information about Industry Segments

The Company is engaged in businesses classified into three segments: Electric, Manufacturing and Plastics. Financial information about the Company's segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 78 through 80 of this Annual Report on Form 10-K.

(c) Narrative Description of Business

ELECTRIC

General

Electric includes OTP which is headquartered in Fergus Falls, Minnesota, and provides electricity to more than 130,000 customers in a service area encompassing 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. The Company derived 49%, 51% and 53% of its consolidated operating revenues and 68%, 72% and 81% of its consolidated operating income from its Electric segment for the years ended December 31, 2018, 2017 and 2016, respectively.

The breakdown of retail electric revenues by state is as follows:

State	2018	2017
Minnesota	52.6 %	52.8 %
North Dakota	38.6	38.5
South Dakota	8.8	8.7
Total	100.0%	100.0%

The territory served by OTP is predominantly agricultural. The aggregate population of OTP’s retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 126,000 people live in communities having a population of more than 1,000, according to the 2010 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,427); Bemidji, Minnesota (13,431); and Fergus Falls, Minnesota (13,138). As of December 31, 2018, OTP served 132,448 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant. One customer accounted for 11% of 2018 Electric segment revenue.

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The following table provides a breakdown of electric revenues by customer category. All other sources include gross wholesale sales from utility generation and sales to municipalities.

Customer Category	2018	2017
Commercial	37.0 %	35.2 %
Residential	32.5	31.1
Industrial	30.0	31.8
All Other Sources	0.5	1.9
Total	100.0%	100.0%

Capacity and Demand

As of December 31, 2018, OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants		
Big Stone Plant	256,400	kW
Coyote Station	151,100	
Hoot Lake Plant	141,000	
Total Baseload Net Plant	548,500	kW
Combustion Turbine and Small Diesel Units	106,200	kW
Hydroelectric Facilities	2,900	kW
Owned Wind Facilities (rated at nameplate)		
Luverne Wind Farm (33 turbines)	49,500	kW
Ashtabula Wind Center (32 turbines)	48,000	
Langdon Wind Center (27 turbines)	40,500	
Total Owned Wind Facilities	138,000	kW

The baseload net plant capacity for Big Stone Plant and Coyote Station constitutes OTP's ownership percentages of 53.9% and 35%, respectively. OTP owns 100% of the Hoot Lake Plant. During 2018, about 63% of OTP's retail kilowatt-hour (kwh) sales were supplied from OTP generating plants with the balance supplied by purchased power.

In addition to the owned facilities described above, OTP had the following purchased power agreements in place on December 31, 2018:

Purchased Wind Power Agreements (rated at nameplate and greater than 2,000 kW)

Ashtabula Wind III	62,400	kW
Edgeley	21,000	
Langdon	19,500	
Total Purchased Wind	102,900	kW
Purchase of Capacity (in excess of 1 year and 500 kW)		
Great River Energy[1]	80,000	kW

[1]80,000 kW through May 2019 and 50,000 kW June 2019 – May 2021.

OTP has a direct control load management system which provides some flexibility to OTP to effect reductions of peak load. OTP also offers rates to customers which encourage off-peak usage.

OTP's capacity requirement is based on MISO Module E requirements. OTP is required to have sufficient Zonal Resource Credits to meet its monthly weather-normalized forecast demand, plus a reserve obligation. OTP met its MISO obligation for the 2018-2019 MISO planning year. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2019 system demand and MISO reserve requirements.

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Fuel Supply

Coal is the principal fuel burned at the Big Stone, Coyote and Hoot Lake generating plants. Coyote Station, a mine-mouth facility, burns North Dakota lignite coal. Hoot Lake Plant and Big Stone Plant burn western subbituminous coal transported by rail.

The following table shows the sources of energy used to generate OTP's net output of electricity for 2018 and 2017:

Sources	2018 Net kwhs Generated (Thousands)	% of Total kwhs Generated		2017 Net kwhs Generated (Thousands)	% of Total kwhs Generated	
Subbituminous Coal	1,891,394	53.5	%	1,440,017	49.1	%
Lignite Coal	1,080,639	30.5		920,451	31.4	
Wind and Hydro	494,394	14.0		534,474	18.2	
Natural Gas and Oil	70,015	2.0		36,703	1.3	
Total	3,536,442	100.0	%	2,931,645	100.0	%

OTP has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Contura Coal Sales, LLC	Wyoming subbituminous	December 31, 2019
Big Stone Plant	Peabody COALSALES, LLC	Wyoming subbituminous	December 31, 2020
Coyote Station	Coyote Creek Mining Company, L.L.C.	North Dakota lignite	December 31, 2040
Hoot Lake Plant	Cloud Peak Energy Resources LLC	Montana subbituminous	December 31, 2023

OTP and its Big Stone Plant co-owners entered into the current coal purchase agreement with Peabody COALSALES, LLC in May 2018 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 the portion to be purchased in 2019 under the agreement with Contura Coal Sales, LLC.

In October 2012 OTP and its Coyote Station co-owners 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 Coyote Station's coal requirements for the period May 2016 through December 2040. The price per ton being paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. The LSA provides for the Coyote Station owners to purchase the membership interests in CCMC in the event of certain early termination events and also at the end of the term of the LSA.

OTP's coal supply requirements for Hoot Lake Plant are secured under contract through December 2023. There are no fixed minimum purchase requirements under this agreement.

Railroad transportation services to the Big Stone Plant and Hoot Lake Plant are provided under a common carrier rate by the BNSF Railway. The common carrier rate is subject to a mileage-based fuel surcharge. The basis for the fuel surcharge is the U.S. average price of retail on-highway diesel fuel. No coal transportation agreement is needed for Coyote Station as a mine-mouth facility.

The average cost of fuel consumed (including handling charges to the plant sites) per million British Thermal Units for the years 2018, 2017, and 2016 was $1.977, $2.224 and $2.146, respectively.

Transmission Revenues

OTP earns significant revenues from the transmission of electricity for others over the transmission assets it separately owns, or jointly owns with other transmission service providers, under rate tariffs established by MISO and approved by the Federal Energy Regulatory Commission (FERC).

General Regulation

OTP is subject to regulation of rates and other matters in each of the three states in which it operates and by the federal government for certain interstate operations.

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A breakdown of electric rate regulation by each jurisdiction follows:

Rates	Regulation	2018 % of Electric Revenues	2018 % of kwh Sales	2017 % of Electric Revenues	2017 % of kwh Sales
MN Retail Sales	MN Public Utilities Commission	46.2 %	54.1 %	46.4 %	54.0 %
ND Retail Sales	ND Public Service Commission	33.9	36.8	33.9	37.1
SD Retail Sales	SD Public Utilities Commission	7.7	9.1	7.7	8.9
Transmission & Wholesale	Federal Energy Regulatory Commission	12.2	--	12.0	--
Total		100.0%	100.0%	100.0%	100.0%

OTP operates under approved retail electric tariffs in all three states it serves. OTP has an obligation to serve any customer requesting service within its assigned service territory. The pattern of electric usage can vary dramatically during a 24-hour period and from season to season. OTP’s tariffs are designed to recover the costs of providing electric service. To the extent peak usage can be reduced or shifted to periods of lower usage, the cost to serve all customers is reduced. In order to shift usage from peak times, OTP has approved tariffs in all three states for residential demand control, general service time of use and time of day, real-time pricing, and controlled and interruptible service. Each of these specialized rates is designed to improve efficient use of OTP resources, while giving customers more control over their electric bill.

With a few minor exceptions, OTP’s electric retail rate schedules currently provide for adjustments in rates based on the cost of fuel delivered to OTP’s generating plants, as well as for adjustments based on the cost of electric energy purchased by OTP. OTP also credits certain margins from wholesale sales to the fuel and purchased power adjustment. The adjustments for fuel and purchased power costs are presently based on a two-month moving average in Minnesota and by the FERC, a three-month moving average in South Dakota and a four-month moving average in North Dakota. These adjustments are applied to the next billing period after becoming applicable. These adjustments also include an over or under recovery mechanism, which is calculated on an annual basis in Minnesota and on a monthly basis in North Dakota and South Dakota. Minnesota has made changes to its fuel and purchased power cost recovery mechanism that will take effect January 1, 2020 (see discussion under Fuel and Purchased Power Costs Recovery below).

2017 Tax Cuts and Jobs Act (TCJA)

The TCJA, passed in December 2017, reduced the federal income tax rate from 35% to 21% effective January 1, 2018 for the Company. At the time of passage, all OTP rates had been developed using a 35% tax rate. In 2018, the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC each initiated dockets or proceedings to begin working with utilities to assess the impact of the lower income tax rate on electric rates, and to develop regulatory strategies to incorporate the tax change into future rates, if warranted.

The MPUC required regulated utilities providing service in Minnesota to make filings by February 15, 2018. On December 5, 2018 the MPUC issued its final order related to the TCJA docket, which directed OTP to return to ratepayers, in a one-time refund, the TCJA-related savings accrued prior to the refund effective date. The order also directed 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. OTP expects the rate change and refund to occur in the second quarter of 2019, pending MPUC approval of OTP's January 3, 2019 compliance filing. As described below, OTP's current general rate cases in North Dakota and South Dakota reflect the impact of the TCJA.

OTP has accrued refund liabilities for the time period when revenues were collected under rates set to recover higher levels of federal income taxes than OTP incurs under the lower federal tax rates in the TCJA. As of December 31, 2018, accrued refund liabilities related to the tax rate reduction were $8.4 million in Minnesota, $0.8 million in North Dakota for amounts collected reflecting the higher tax rate under interim rates in effect in January and February 2018, $1.0 million in South Dakota billed prior to October 18, 2018, and $0.2 million for FERC jurisdictional rates.

On 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 TCJA impacts.

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Electric Segment Major Capital Expenditure Projects

Below are descriptions of OTP’s major capital expenditure projects that have had, or will have, a significant impact on OTP’s revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of the material regulations of each jurisdiction applicable to OTP’s electric operations, as well as any specific electric rate proceedings during the last three years with the MPUC, the NDPSC, the SDPUC and the FERC.

Merricourt Project—On November 16, 2016 OTP entered into an Asset Purchase Agreement (the Purchase Agreement) with EDF Renewable Development, Inc. and certain of its affiliated companies (EDF) to purchase and assume the development assets and certain specified liabilities associated with a 150-megawatt (MW) wind farm in southeastern North Dakota (the Merricourt Project) for a purchase price of approximately $34.7 million, subject to adjustments for interconnection costs. The Purchase Agreement will close on satisfaction of various closing conditions (including regulatory approvals). Also on November 16, 2016, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement with EDF pursuant to which EDF will develop, design, procure, construct, interconnect, test and commission the wind farm with a targeted completion date in 2020 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. Depending on the timing of MISO interconnection approval, construction of the Merricourt Project is currently anticipated to begin in mid-2019. The agreements contain customary representations, warranties, covenants and indemnities for this type of transaction. As of December 31, 2018, OTP had capitalized approximately $4.9 million in development costs associated with the Merricourt Project. A final order for an Advance Determination of Prudence (ADP), subject to qualifications and compliance obligations, and a Certificate of Public Convenience and Necessity were issued by the NDPSC on November 3, 2017. On October 26, 2017 the MPUC approved the facility under the Renewable Energy Standard making the Merricourt Project eligible for cost recovery under the Minnesota Renewable Resource Recovery rider, subject to qualifications and reporting obligations.

Astoria Station—OTP is moving forward with plans for the development, construction and ownership of this 250-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. OTP expects the project will cost approximately $158 million. As of December 31, 2018, OTP had capitalized approximately $8.3 million in development costs associated with Astoria Station. On August 3, 2018 the SDPUC issued an order granting a site permit for Astoria Station. A final order granting ADP for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations. The interconnection agreement for Astoria Station was executed by MISO in December 2018 and accepted by the FERC in January 2019. In a September 26, 2018 hearing the NDPSC approved an overall annual revenue increase for OTP and established a Generation Cost Recovery rider for future recovery of costs incurred for Astoria Station.

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345 kiloVolt (kV) transmission line that 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 will 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. Construction began on this line in the second quarter of 2016 and the line was energized on February 6, 2019. OTP's capitalized costs on this project as of December 31, 2018 were approximately $106 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings 345-kV MVP—OTP invested approximately $73 million (including assets that are 100% owned by OTP) and has a 50.0% ownership interest in the jointly-owned assets of this 70-mile transmission line energized in 2017.

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

Minnesota

Under the Minnesota Public Utilities Act (the MPU Act), OTP is subject to the jurisdiction of the MPUC with respect to rates, issuance of securities, depreciation rates, public utility services, construction of major utility facilities, establishment of exclusive assigned service areas, contracts and arrangements with subsidiaries and other affiliated interests, and other matters. The MPUC has the authority to assess the need for large energy facilities and to issue or deny certificates of need, after public hearings, within one year of an application to construct such a facility.

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Pursuant to the Minnesota Power Plant Siting Act, the MPUC has authority to select or designate sites in Minnesota for new electric power generating plants (50,000 kW or more) and routes for transmission lines (100 kV or more) in an orderly manner compatible with environmental preservation and the efficient use of resources, and to certify such sites and routes as to environmental compatibility after an environmental impact study has been conducted by the Minnesota Department of Commerce (MNDOC) and the Office of Administrative Hearings has conducted contested case hearings.

The Minnesota Division of Energy Resources, part of the MNDOC, is responsible for investigating all matters subject to the jurisdiction of the MNDOC or the MPUC, and for the enforcement of MPUC orders. Among other things, the MNDOC is authorized to collect and analyze data on energy including the consumption of energy, develop recommendations as to energy policies for the governor and the legislature of Minnesota and evaluate policies governing the establishment of rates and prices for energy as related to energy conservation. The MNDOC also has the power, in the event of energy shortage or for a long-term basis, to prepare and adopt regulations to conserve and allocate energy.

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

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 Environmental Cost Recovery (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.

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

Integrated Resource Plan (IRP)—Minnesota law requires utilities to submit to the MPUC for approval a 15-year advance IRP. A resource plan is a set of resource options a utility could use to meet the service needs of its customers over a forecast period, including an explanation of the utility's supply and demand circumstances, and the extent to which each resource option would be used to meet those service needs. The MPUC's findings of fact and conclusions regarding resource plans shall be considered prima facie evidence, subject to rebuttal, in Certificate of Need (CON) hearings, rate reviews and other proceedings. Typically, resource plans are submitted every two years.

On April 26, 2017 the MPUC issued an order approving OTP's 2017-2031 IRP filing with modifications and setting requirements for the next resource plan. The approved plan with modifications included the following items:

- The addition of 200 MW of wind resources in the 2018 to 2020 timeframe.
- The addition of 30 MW of solar resources by 2020 to comply with Minnesota's Solar Energy Standard.
- The addition of up to 250 MW of peaking capacity in 2021.
- Average annual energy savings of 46.8 gigawatt-hours (1.6% of retail sales).
- Modification of OTP's IRP to include an additional 100 MW to 200 MW of wind in the 2022 to 2023 timeframe.

On November 29, 2018 the MPUC extended the deadline for OTP's next IRP filing from June 3, 2019 to June 1, 2020. The MPUC order cited two key environmental regulations for which the impacts on OTP facilities are not yet ascertainable: the federal Regional Haze Rule promulgated by the Environmental Protection Agency (EPA) in 1999 and the Affordable Clean Energy (ACE) Rule proposed by the EPA in August 2018.

Fuel and Purchased Power Costs Recovery—The MPUC has issued an order authorizing the implementation of a new fuel clause adjustment mechanism to be implemented January 1, 2020. Prior to implementation, OTP will be required to submit forecasted monthly fuel cost rates for the twelve-month period beginning January 1, 2020. On approval by the MPUC, those rates will be published in advance of each year to give customers notice of the next year's monthly fuel rates, and those will be the rates OTP will charge per kwh to cover fuel costs. OTP will track its actual costs throughout the year and then file an annual report with the MPUC comparing the actual cost per kwh to the billed cost per kwh to determine if any over or under collection of costs occurred. OTP would refund any over-collections, or in the case of an under-collection, be required to show prudence of costs incurred over forecast before being authorized recovery. The refund of any over-collection or recovery of any under-collection would be handled through a true-up mechanism. OTP is working with other Minnesota utilities, the MNDOC and other stakeholders to address questions and further develop the mechanism prior to implementation.

On MPUC finalization of an order implementing the mechanism, OTP will be required to reserve revenues, accrue a liability and refund amounts of fuel and purchased power and related costs collected in excess of amounts for which it was granted recovery in its most recent rate case or annual fuel cost adjustment filing preceding the annual period of recovery. OTP will continue to accrue revenue and a regulatory asset for fuel and purchased power costs incurred in excess of amounts recovered under the adjustment mechanism unless and until recovery of those excess amounts are deemed not prudent and recovery is not granted through the true-up mechanism in a subsequent order by the MPUC. This mechanism could result in reductions in Electric segment operating income margins and could increase variability in consolidated net income in future periods if costs per kwh vary from forecasted costs per kwh and recovery of all or a portion of excess costs is denied by the MPUC.

Renewable Energy Standards, Conservation, Renewable Resource Riders—Minnesota law favors energy conservation and load-management measures over the addition of new generation resources. In addition, Minnesota law requires the use of renewable resources where new supplies are needed, unless the utility proves that a renewable energy facility is not in the public interest. Minnesota law requires the MPUC, to the extent practicable, to quantify the environmental costs associated with each method of electricity generation, and to use such monetized values in evaluating generation resources. The MPUC must disallow any nonrenewable rate base additions (whether within or outside of the state) or any related rate recovery and may not approve any nonrenewable energy facility in an IRP, unless the utility proves that a renewable energy facility is not in the public interest. The state has prioritized the acceptability of new generation with wind and solar ranked first, the highest ranking, and coal and nuclear ranked fifth, the lowest ranking. The MPUC's currently applicable estimate of the range of costs of future carbon dioxide (CO_2) regulation to be used in modeling analyses for resource plans is $5.00 to $25.00 per ton of CO_2 commencing in 2025. The MPUC is required to annually update these estimates.

Minnesota has a renewable energy standard which requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 17% by 2016; 20% by 2020 and 25% by 2025. In addition, Minnesota law requires 1.5% of total Minnesota electric sales by public utilities to be supplied by solar energy by 2020. For a public utility with between 50,000 and 200,000 retail electric customers, such as OTP, at least 10% of the 1.5% requirement must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kWs or less. If approved by the MPUC, individual customer subscriptions to an OTP-operated community solar garden program of 40 kWs or less could be applied toward the 10% requirement. OTP has purchased sufficient solar renewable energy credits (SRECs) to meet 100 percent of its 2020 obligation and approximately 70% of its 2021 obligation.

Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired enough renewable resources to comply with current requirements under Minnesota renewable energy standards. OTP is evaluating potential options for maintaining compliance and meeting the solar energy standard. Projected capital expenditures include $30 million for solar generation in 2022. OTP’s compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standard. The MPUC is authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

Minnesota Conservation Improvement Programs (MNCIP)—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are included as recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

On May 25, 2016 the MPUC adopted the MNDOC’s proposed changes to the MNCIP financial incentive. The new model provides utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. The financial incentive is also limited to 40% of 2017 MNCIP spending, 35% of 2018 spending and 30% of 2019 spending. The new model reduces the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

On April 1, 2016 OTP requested approval for recovery of its 2015 MNCIP program costs not included in base rates, a $4.3 million financial incentive and an update to the MNCIP surcharge from the MPUC. On July 19, 2016 the MPUC issued an order approving OTP’s request with an effective date of October 1, 2016.

Based on results from the 2016 MNCIP program year, OTP recognized MNCIP financial incentives of $5.1 million in 2016, which included a $0.1 million true-up of 2015 financial incentives earned. The 2016 program resulted in an approximate 18% increase in energy savings compared to 2015 program results. On March 31, 2017 OTP requested approval for recovery of its 2016 MNCIP program costs not included in base rates, $5.0 million in performance incentives and an update to the MNCIP surcharge from the MPUC. On September 15, 2017 the MPUC issued an order approving OTP’s request with an effective date of October 1, 2017.

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of $2.6 million in 2017. The 2017 program resulted in a decrease in energy savings compared to 2016 program results of approximately 10%. OTP requested approval for recovery of its 2017 MNCIP program costs not included in base rates on March 30, 2018. The request included a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC. On June 13, 2018, in reply comments to a MNDOC recommendation for approval filed on May 30, 2018, OTP increased its request for a financial incentive to $2.9 million. On October 4, 2018, the MPUC issued an order approving OTP’s request of $2.9 million with an effective date of November 1, 2018, subject to further review by the MPUC to ensure no previous decisions conflict with the decision, with $0.3 million subject to possible refund.

Based on results from the 2018 MNCIP program year, OTP recognized $3.0 million out of a potential $3.15 million in financial incentives earned in 2018. OTP will request approval for recovery of its 2018 program costs not included in base rates, a $3.15 million financial incentive and an update to its MNCIP surcharge from the MPUC by April 1, 2019.

In 2016 the MNDOC opened a docket to investigate how investor-owned utilities calculate their avoided costs pertaining to transmission and distribution. Avoided costs are the basis of MNCIP program benefits which, going forward, will establish OTP's financial incentive. On May 23, 2016 the MNDOC accepted OTP's 2017 avoided costs calculation but required Minnesota investor-owned utilities to undergo an analysis of transmission and distribution avoided costs for 2018 and 2019. OTP is participating in a stakeholder group with the MNDOC, Xcel Energy Inc., and Minnesota Power to determine the best method for calculating avoided costs. On September 29, 2017, the MNDOC issued a decision on utilities' transmission and distribution avoided costs. The decision did not require OTP to update avoided costs or cost-effectiveness for the 2017-2019 MNCIP triennial plan. The decision directed OTP to use the discrete approach methodology to calculate avoided transmission and distribution costs as part of OTP's 2020-2022 MNCIP triennial plans.

Transmission Cost Recovery Rider—The MPU Act authorizes the MPUC to approve a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a CON proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or that are exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system.

The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's most recently completed general rate case or such other rate of return the MPUC determines is in the public interest. Additionally, following approval of a rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

OTP filed an annual update to its Minnesota TCR rider on September 30, 2015 requesting revenue recovery of approximately $7.8 million. A supplemental filing to the update was made on December 21, 2015 to address an issue surrounding the proration of accumulated deferred income taxes and, in an unrelated adjustment, the TCR rider update revenue request was reduced to $7.2 million. On March 9, 2016 the MPUC issued an order approving OTP's annual update to its TCR rider, with an effective date of April 1, 2016.

OTP filed an update to its TCR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis, as recommended by the MNDOC. The proposed rate changes went into effect on September 1, 2016. On October 30, 2017 the MPUC issued an order resetting OTP's Minnesota TCR rates in effect since September 1, 2016 to refund $3.3 million previously collected under the rider, beginning November 1, 2017. The reset rates were approved on a provisional basis in the Minnesota general rate case docket, subject to revision in a separate docket.

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 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 can vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to jurisdictionally allocate costs of the FERC MVP transmission projects in the TCR rider.

On 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 has granted review of the Minnesota Court of Appeals decision. A decision by the Minnesota Supreme Court is expected in either second or third quarter 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. In both situations the rates are proposed to be effective June 1, 2019 if a decision is made in late first quarter or early second quarter 2019. If the decision is made later than second quarter of 2019, it is likely the MPUC will delay its decision on the TCR rider update. The amount credited to Minnesota customers under the TCR through December 31, 2018 and subject to recovery if the Minnesota Court of Appeals decision is upheld, is approximately $2.3 million.

Environmental Cost Recovery Rider—The Minnesota ECR rider provided 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. The MPUC issued an order on March 9, 2016 approving OTP's request to leave the 2014 annual update rate in place. OTP filed an update to its Minnesota ECR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request, with an effective date of September 1, 2016. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis. On October 30, 2017 the MPUC issued an order resetting OTP's Minnesota ECR rate in effect since September 1, 2016 to refund $1.9 million previously collected under the rider, beginning November 1, 2017. In its 2016

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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.

Reagent Costs and Emission Allowances—These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the Fuel Clause Adjustment (FCA) rider or base rates. In its 2016 general rate case order issued May 1, 2017 the MPUC denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs and through the FCA rider. Instead, the test-year costs are being recovered in base rates and variability of those costs in excess of amounts included in base rates will only be recovered to the extent actual kwh sales exceed forecasted kwh sales used to establish base rates.

Capital Structure Petition—Minnesota law requires an annual filing of a capital structure petition with the MPUC. In this filing the MPUC reviews the capital structure for OTP. Once the petition is approved, OTP may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved capital structure petition. The MPUC approved OTP's most recent capital structure petition on October 18, 2018, allowing for an equity-to-total-capitalization ratio between 47.9% and 58.5%, with total capitalization not to exceed $1,204,416,000 until the MPUC issues a new capital structure order for 2019. OTP is required to file its 2019 capital structure petition no later than May 1, 2019.

North Dakota

OTP is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities, construction of major utility facilities and other matters. The NDPSC periodically performs audits of gas and electric utilities over which it has rate setting jurisdiction to determine the reasonableness of overall rate levels. In the past, these audits have occasionally resulted in settlement agreements adjusting rate levels for OTP.

The North Dakota Energy Conversion and Transmission Facility Siting Act grants the NDPSC the authority to approve sites and routes in North Dakota for large electric generating facilities and high voltage transmission lines, respectively. This Act is similar to the Minnesota Power Plant Siting Act described above and applies to proposed wind energy electric power generating plants exceeding 500 kW of electricity, non-wind energy electric power generating plants exceeding 50,000 kW and transmission lines with a design in excess of 115 kV. OTP is also required to submit a ten-year facility plan to the NDPSC biennially.

The NDPSC reserves the right to review the issuance of stocks, bonds, notes and other evidence of indebtedness of a public utility. However, the issuance by a public utility of securities registered with the SEC is expressly exempted from review by the NDPSC under North Dakota state law.

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 Renewable Resource Adjustment (NDRRA), TCR and ECR rider revenues that would have resulted from a lower allowed rate of return on equity and changes in allocation factors in the general rate case. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.30%. On December 20, 2017 the NDPSC approved OTP's request for interim rates to increase annual revenue collections by $12.8 million, effective January 1, 2018. 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 Generation Cost Recovery 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 will be effective February 1, 2019, with refunds of excess revenues collected under interim rates applied to customers' April 2019 bills. OTP has accrued an interim rate refund of $3.0 million as of December 31, 2018, which includes the $0.8 million in excess revenue collected for income taxes under interim rates in effect in January and February 2018.

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Renewable Resource Adjustment—OTP has a NDRRA rider which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016. On February 25, 2016 OTP made a supplemental filing to address the impact of bonus depreciation for income taxes and related deferred tax assets on the NDRRA, as well as an adjustment to the estimated amount of federal production tax credits (PTCs) used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflected a reduction in the ROE component of the rate from 10.75%, approved in OTP’s 2008 general rate case, to 10.50%. OTP submitted its 2016 annual update to the NDRRA rider rate on December 30, 2016, requesting a decrease to the NDRRA rate from 7.573% to 7.005%. The NDPSC approved the NDRRA 2016 annual update on March 15, 2017 with an effective date of April 1, 2017.

In conjunction with OTP’s November 2, 2017 general rate case filing, OTP submitted an updated proposal to adjust the NDRRA rate to reflect updated costs and collections, as well as reflect a rate of return and capital structure level consistent with those proposed in the general rate case. The NDPSC approved the update to the NDRRA rate in conjunction with approving the rate case interim rates and the NDRRA rate increased from 7.005% to 7.756% with an effective date of January 1, 2018. A reset of the NDRRA rate to reflect the effect of the federal corporate tax rate reduction under the TCJA was approved on February 27, 2018, reducing the NDRRA rate to 7.493%, effective March 1, 2018.

In a filing to the NDPSC on December 31, 2018 OTP requested approval for an annual update to its NDRRA rider rate to -0.224% of base charges, based on an annual refund requirement of $236,000, to be effective for bills rendered on and after April 1, 2019. The refund requirement results from recovery of the Ashtabula, Langdon, and Luverne wind projects being moved into base rates as of December 31, 2018 as well as a reduction in revenue requirements related to the difference between the deferred tax asset for PTCs included in base rates and actual amounts associated with the Ashtabula and Langdon wind projects.

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 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.

On September 1, 2016 OTP filed its annual update to the TCR rider requesting a revenue requirement of $5.7 million, including a reduction of $2.6 million for a projected over-collection for 2016. Primary drivers of a decrease from the 2015 updated rider rate include the impact of federal bonus depreciation and unresolved MISO ROE complaint proceedings. OTP filed a supplemental filing on September 14, 2016, requesting that the over-collection balance be spread over two succeeding years to reduce the volatility from year to year. The NDPSC approved the update on December 14, 2016. The new rates went into effect on January 1, 2017.

On August 31, 2017 OTP filed its annual update to the TCR rider requesting a revenue requirement of $8.6 million. OTP made a supplemental filing on November 2, 2017, reducing its request by $0.6 million to $8.0 million to reflect the rate of return and allocation factors used in its general rate case filed the same day. The NDPSC approved the update for recovery of the $8.0 million revenue requirement on November 29, 2017 and the new rates went into effect on January 1, 2018. A reset of the TCR rate to reflect the effect of the federal corporate tax rate reduction under the TCJA was approved on February 27, 2018, reducing annual revenue recovery under the TCR rate by $0.5 million effective March 1, 2018.

On August 31, 2018 OTP filed its annual update to the TCR rider. The filing included three new projects along with updates to collections, actual costs and forecasted amounts for rider-eligible projects. The filing also reflected projects moving to base rates proposed to become effective in October 2018, in the above-described general rate case. On November 7, 2018 OTP filed a supplement to the TCR rider update indicating two of the three new projects had been postponed and the roll-in of rider costs to base rates was calculated based on a change to January 1, 2019. The update request was approved by the NDPSC on December 6, 2018 and the updated rates went into effect with bills rendered on or after February 1, 2019 to coincide with the launch of OTP's new customer information and billing system.

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Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxic Standards (MATS) projects. The ECR rider 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 reagent and emission allowance costs.

On March 31, 2016 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 9.193% to 7.904% of base rates, or a revenue requirement reduction from $12.2 million to $10.4 million, effective July 1, 2016. The rate reduction request was primarily due to the Company's 2015 bonus depreciation election for income taxes, which reduces revenue requirements. The filing was approved on June 22, 2016.

On March 31, 2017 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 7.904% to 7.633% of base rates, or a revenue requirement reduction from $10.4 million to $9.9 million, effective August 1, 2017. The rate reduction request was primarily due to a reduction in the projects' unrecovered costs and lower net book values as a result of depreciation. The filing was approved on July 12, 2017.

In conjunction with OTP's November 2, 2017 general rate case filing, OTP submitted an updated proposal to adjust the ECR rider rate to reflect updated costs and collections and a rate of return and capital structure level consistent with those proposed in the general rate case. The NDPSC approved the update to the ECR rider rate in conjunction with approving the general rate case interim rates. The new ECR rate decreased from 7.633% to 6.629% with an effective date of January 1, 2018. A reset of the ECR rate to reflect the effect of the federal corporate tax rate reduction under the TCJA was approved on February 27, 2018, reducing the ECR rate to 5.593%, effective March 1, 2018.

Based on the order in the 2017 general rate case, project costs previously being recovered under the rider would be recovered in base rates and reagent and emission allowance costs will be recovered through the energy adjustment rider. The rider was zeroed out at the implementation of final rates on February 1, 2019, except for an overcollection balance that will be refunded to ratepayers through the rider.

South Dakota

Under the South Dakota Public Utilities Act, OTP is subject to the jurisdiction of the SDPUC with respect to rates, public utility services, construction of major utility facilities, establishment of assigned service areas and other matters. Under the South Dakota Energy Facility Permit Act, the SDPUC has the authority to approve sites in South Dakota for large energy conversion facilities (100,000 kW or more) and most transmission lines with a design of 115 kV or more.

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. On February 5, 2019 SDPUC staff and OTP requested that the SDPUC issue a procedural schedule setting evidentiary hearings for March 26-28, 2019. The full effects of the TCJA on South Dakota revenue requirements will be addressed in the rate case and incorporated into final rates at the conclusion of that case. The second step in the request is an additional 1.7% increase to recover costs for the proposed Merricourt wind generation facility when the facility goes into service. On February 15, 2019 the Company reached a partial settlement with SDPUC staff which requires SDPUC approval.

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 to recover its South Dakota jurisdictional share of the revenue requirements associated with its investment in new or modified electric transmission facilities. OTP filed its 2015 annual update on October 30, 2015 with a proposed effective date of March 1, 2016. A supplemental filing was made on February 3, 2016 to true-up the filing to include the impact of bonus depreciation elected for 2015, the inclusion of a deferred tax asset relating to a net operating loss and the proration of accumulated deferred income taxes. This update included the recovery of new SPP transmission costs OTP began to incur on January 1, 2016. On February 12, 2016 the SDPUC approved OTP’s annual update to its TCR rider, with an effective date of March 1, 2016. On November 1, 2016 OTP filed the annual update to the South Dakota TCR rider. OTP made a supplemental filing on January 20, 2017 to include updated costs through December 2016 as well as updated forecast information. On February 17, 2017 the SDPUC approved OTP’s annual update to its TCR rider, with an effective date of March 1, 2017. On November 1, 2017 OTP filed the annual update to the South Dakota TCR rider with a requested annual revenue requirement of $1.8 million and effective date of March 1, 2018. A supplemental filing was made on January 29, 2018 to reflect updated costs and collections and incorporate the impact of the federal corporate income tax rate under the TCJA. The updated annual revenue requirement request was $1.8 million. Effective October 18, 2018, with the implementation of interim rates under South Dakota general rate case proceedings, the TCR rate was decreased to reflect an annual revenue requirement of $1.2 million as a result of certain costs being transitioned to recovery through interim rates and proposed for ongoing recovery in final base rates at the conclusion of the pending general rate case.

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Environmental Cost Recovery Rider— OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects. On August 31, 2016 OTP filed its 2016 update to the ECR rider, requesting recovery of approximately $2.2 million in annual revenue. The SDPUC approved the request on October 26, 2016 with an effective date of November 1, 2016. The lower revenue requirement is a result of the implementation of federal bonus depreciation taken on the Big Stone Plant AQCS. On August 31, 2017 OTP filed its 2017 update to the ECR rider, requesting recovery of approximately $2.1 million in annual revenue. The SDPUC approved the request on October 13, 2017 with an effective date of November 1, 2017. Effective October 18, 2018, with the implementation of interim rates under South Dakota general rate case proceedings, the ECR rate was decreased to -$0.00075/kwh to refund $0.2 million previously collected under the rider, and the ECR-eligible costs are proposed for ongoing recovery in final base rates at the end of the 2018 general rate case described above.

Reagent Costs and Emission Allowances—OTP’s South Dakota jurisdictional share of reagent costs and emission allowances is currently being recovered in its South Dakota FCA rider.

Energy Efficiency Plan (EEP)—The SDPUC has encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use. The plan is being implemented with program costs, carrying costs and a financial incentive being recovered through an approved rider.

On April 29, 2016 OTP filed its 2015 South Dakota EEP Status Report, financial incentive and surcharge adjustment with the SDPUC. The filing requested approval of an incentive of $105,900 and a decrease in the EEP surcharge from $0.00152/kwh to $0.00114/kwh effective July 1, 2016. The SDPUC approved the request. On April 29, 2016 OTP also filed its 2017-2019 goals and budgets for its South Dakota EEP triennial plan. For the 2017, 2018 and 2019 EEP planning years, OTP has proposed energy savings goals and budgets of 3,804,094 kwh and $449,000 in 2017, 3,805,177 kwh and $449,000 in 2018 and 3,806,262 kwh and $449,000 in 2019. On November 22, 2016 the SDPUC approved OTP’s 2017-2019 EEP triennial plan with certain conditions.

On May 1, 2017 OTP filed its 2016 South Dakota EEP Status Report, financial incentive and surcharge adjustment with the SDPUC. The filing requested approval of an incentive of $105,900 and an increase in the EEP surcharge from $0.00114/kwh to $0.00138/kwh effective July 1, 2017. The SDPUC approved the request on June 21, 2017.

On May 1, 2018, OTP filed its 2017 South Dakota EEP Status Report, financial incentive, and surcharge adjustment with the SDPUC. The filing requested approval of an incentive of $134,700 and an increase in the EEP surcharge from $0.00138/kwh to $0.00155/kwh effective July 1, 2018. The SDPUC approved the request on June 26, 2018. On September 21, 2018 OTP filed a modification to its 2016-2019 EEP Plan. This modification requested an additional $250,000 annually for three years starting in 2019. The increased budget was requested to pay additional rebates for a large customer that is planning to make significant energy efficiency investments in its expanding facilities. On December 11, 2018, the SDPUC approved the request.

FERC

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

MVPs—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing.

Effective January 1, 2012 the FERC authorized OTP to recover 100% of prudently incurred CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVPs in MISO’s 2011 Transmission Expansion Plan: the Big Stone South–Brookings MVP and the Big Stone South–Ellendale MVP.

Transmission Tariff ROE Complaints—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.

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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 was 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

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

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

In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the two ROE complaints involving MISO transmission owners discussed above. In April 2017 the U.S. Court of Appeals for the District of Columbia Circuit (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 the 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 the MISO transmission owners. Initial briefs were due February 13, 2019 and reply briefs are due April 10, 2019.

OTP believes its estimated accrued MISO Tariff ROE refund liability of $1.6 million as of December 30, 2018 related to the second MISO tariff ROE complaint is appropriate.

NAEMA

OTP is a member of the North American Energy Marketers Association (NAEMA) which is an independent, non-profit trade association representing entities involved in the marketing of energy or in providing services to the energy industry. NAEMA has over 150 members with operations in 48 states and Canada. Power pool sales are conducted continuously through NAEMA in accordance with schedules filed by NAEMA with the FERC.

North American Electric Reliability Corporation (NERC)

NERC has regulatory authority spanning the United States, Canada and the northern portion of Baja California, Mexico, and is subject to oversight by the FERC and governmental authorities in Canada. NERC's mission is to assure the reliability of the bulk power system in North America. As an owner and operator within the bulk power system, OTP is required to comply with NERC reliability standards, including standards on cybersecurity and protection of critical infrastructure.

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Midwest Reliability Organization (MRO)

OTP is a member of the MRO. The MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO began operations in 2005 and is one of eight regional entities in North America operating under authority from regulators in the United States and Canada through a delegation agreement with the NERC. The MRO is responsible for: (1) developing and implementing reliability standards, (2) enforcing compliance with those standards, (3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity, and (4) providing an appeals and dispute resolution process.

The MRO region covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska and the majority of territory in the states of South Dakota, Iowa and Wisconsin. The region includes more than 130 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, independent power producers and others who have interests in the reliability of the bulk power system.

To ensure our compliance with NERC standards, the MRO periodically audits OTP. MRO's current audit of OTP began with notification in October 2018. The final report is not expected for several months.

MISO

OTP is a member of the MISO. The MISO operates the transmission facilities owned by others and administers energy and generation capacity markets. As the transmission provider and security coordinator for the region, the MISO seeks to optimize the efficiency of the interconnected system, provide solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions. The MISO covers a broad region including all or parts of 15 states and the Canadian province of Manitoba. The MISO has operational control of OTP's transmission facilities above 100 kV, but OTP continues to own and maintain its transmission assets.

Through the MISO day-ahead and real-time energy markets, MISO seeks to develop options for energy supply, increase utilization of transmission assets, optimize the use of energy resources across a wider region and provide greater visibility of data. The MISO aims to facilitate a more cost-effective and efficient use of the wholesale bulk electric system.

The MISO Ancillary Services Market (ASM) facilitates the provision of Regulation, Spinning Reserve and Supplemental Reserves. The ASM integrates the procurement and use of regulation and contingency reserves with the existing Energy Market. OTP has actively participated in the market since its commencement.

Other

OTP is subject to various federal laws, including the Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992 (which are intended to promote the conservation of energy and the development and use of alternative energy sources) and the Energy Policy Act of 2005.

Competition, Deregulation and Legislation

Electric sales are subject to competition in some areas from municipally owned systems, rural electric cooperatives and, in certain respects, from on-site generators and cogenerators. Electricity also competes with other forms of energy. The degree of competition may vary from time to time depending on relative costs and supplies of other forms of energy.

The Company believes OTP is well positioned to be successful in a competitive environment. A comparison of OTP’s electric retail rates to the rates of other investor-owned utilities, cooperatives and municipals in the states OTP serves indicates OTP’s rates are competitive.

Legislative and regulatory activity could affect operations in the future. OTP cannot predict the timing or substance of any future legislation or regulation. The Company does not expect retail competition to come to the states of Minnesota, North Dakota or South Dakota in the foreseeable future. There has been no legislative action regarding electric retail choice in any of the states where OTP operates. The Minnesota legislature has in the past considered legislation that, if passed, would have limited the Company’s ability to maintain and grow its nonelectric businesses.

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OTP is currently participating in a Distributed Generation (DG) Workgroup in Minnesota in a docket established by the MPUC. Distributed energy resources are utility- or customer-owned resources on the distribution grid that can include combined heat and power, solar photovoltaic, wind, battery storage, thermal storage, and demand-response technologies. DG is the generation of electricity on-site or close to where it is needed in small facilities designed to meet local needs. Advances in technology and economics are contributing to increasing interest in DG in Minnesota and consumer requests for DG will likely grow. OTP is working to accurately identify and quantify the impacts (including costs and values) of DG; this can be difficult because the impacts of DG vary geographically and over time.

In 2011 the FERC required some electric transmission providers, including the MISO, to remove from their tariffs a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. However, state laws allowing rights of first refusal to construct electric transmission infrastructure still exist in Minnesota, North Dakota and South Dakota.

OTP and other Minnesota electric transmission owners (Amici Utilities) are involved in a federal lawsuit and subsequent 8th Circuit appeal filed by LSP Transmission Holdings, LLC (LSP) challenging a Minnesota statute granting incumbent electric transmission owners a right of first refusal to construct new transmission facilities connected to existing facilities. LSP has argued that the Minnesota law violates the dormant Commerce Clause of the U.S. Constitution. A federal district court rejected that argument, and LSP appealed. The Amici Utilities support the Minnesota right of first refusal law as a reasoned policy judgment by the State of Minnesota and thus not subject to challenge under the dormant Commerce Clause. The appeal is currently being briefed, and it is unknown at this time when a decision will be issued.

OTP has been involved in a MISO process re-establishing the right of transmission owners to elect the initial funding of electric transmission projects required to support the interconnection of the generator’s project to the MISO transmission system. In 2018 the D.C. Circuit vacated earlier FERC orders limiting transmission owners’ initial funding of transmission upgrade projects required by generator interconnections. As a result, the MISO Tariff and related agreements establish once again that MISO transmission owners have the discretion to initially fund the construction of certain qualifying interconnection-related transmission upgrades. Thus, the Company, as a MISO transmission owner, can invest the initial capital for such qualifying upgrades and earn a return on and of the capital investment from interconnection customers.

OTP is unable to predict the impact on its operations resulting from future regulatory activities, from future legislation or from future taxes that may be imposed on the source or use of energy.

Environmental Regulation

Impact of Environmental Laws—OTP’s existing generating plants are subject to stringent federal and state standards and regulations regarding, among other things, air, water and solid waste pollution. In the five years ended December 31, 2018 OTP invested approximately $120.4 million in environmental control facilities. The 2019 and 2020 construction budgets include approximately $4.2 million and $0.3 million, respectively, for environmental equipment for existing facilities. Additional expenditures may be required depending on the outcome of various environmental regulations currently under consideration for implementation, and such expenditures could be material.

Air Quality - Criteria Pollutants—Pursuant to the Clean Air Act (CAA), the Environmental Protection Agency (EPA) has promulgated national primary and secondary standards for certain air pollutants.

The primary fuels burned by OTP’s steam generating plants are North Dakota lignite coal and western subbituminous coal. Hoot Lake Plant, Big Stone Plant, and Coyote Station are currently operating within all presently applicable federal and state air quality and emission standards.

The CAA, in addressing acid deposition, imposed requirements on power plants in an effort to reduce national emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x).

The national Acid Rain Program SO_2 emission reduction goals are achieved through a market-based system under which power plants are allocated "emissions allowances" that require plants to either reduce their SO_2 emissions or acquire allowances from others to achieve compliance. Each allowance is an authorization to emit one ton of SO_2. SO_2 emission requirements are currently being met by all of OTP’s generating facilities without the need to acquire additional allowances for compliance.

The national Acid Rain Program NO_x emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. All of OTP’s generating facilities met the NO_x standards during 2018.

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The Cross-State Air Pollution Rule (CSAPR) requires SO2 and NOx emission reductions in primarily eastern states in order to allow downwind states to achieve national ambient air quality standards (NAAQS). CSAPR's Phase 1 emission budgets began on January 1, 2015 for the annual SO2 and NOx programs, with stricter Phase 2 budgets beginning in 2017.

The CSAPR rule applies to OTP’s Solway gas peaking plant and the Hoot Lake coal-fired plant in Minnesota. Minnesota is considered a Group 2 state for SO2 compliance. Any SO2 allowances that need to be obtained for Hoot Lake Plant will need to be from an entity in a Group 2 state. Hoot Lake met the CSAPR requirements in 2018 without acquiring additional allowances.

On September 7, 2016 the EPA finalized an update to the CSAPR to address interstate emission transport with respect to the more recent 2008 ozone NAAQS. The updated CSAPR does not apply to Minnesota, North Dakota and South Dakota.

On October 1, 2015 the EPA announced that it tightened the primary and secondary NAAQS for ozone from 75 parts per billion (ppb) to 70 ppb. On November 16, 2017 EPA issued a final rule determining that all of the areas in the states in which OTP operates will be designated as attainment/unclassifiable.

In June 2010, the EPA established a new primary NAAQS for SO2 at a level of 75 ppb on a 1-hour average. Designations for this standard proceeded under several different pathways. For certain large sources, including Big Stone Plant and Coyote Station, the EPA entered into a consent decree with the Sierra Club/Natural Resources Defense Council that required the EPA to promulgate final designations near those sources by July 2, 2016. On June 30, 2016, the EPA signed a final rule that designated the areas around Big Stone Plant and Coyote Station as being in attainment/unclassifiable with the 1-hour SO2 NAAQS. Numerous other sources, including Hoot Lake Plant, are covered by the EPA's final Data Requirements Rule (DRR) that was finalized in August 2015. The DRR requires states to provide either modeling or monitoring data to adequately characterize SO2 emissions surrounding those sources. Based on modeling, in January 2018, the EPA published a final determination of attainment/unclassifiable for the county in which Hoot Lake Plant is located.

Air Quality – Hazardous Air Pollutants—On December 16, 2011 the EPA signed a final rule to reduce mercury and other air toxics emissions from power plants known as the MATS rule. With the installation of new pollution control equipment in 2015, OTP's affected units are meeting current requirements. Emissions monitoring equipment and/or stack testing is being used to verify compliance with the standards. Litigation surrounding the MATS rule is ongoing despite the expiration of the compliance deadlines, and the rule remains in effect while the litigation continues. On December 28, 2018 EPA issued a proposed rule that provides that it is not “appropriate and necessary” to regulate hazardous air pollutants from power plants; however, EPA concludes that this new finding would not cause it to rescind MATS. The proposed rule also addresses the CAA requirement to conduct a risk and technology review for power plants, which concludes no revisions to MATS are warranted.

Air Quality – EPA New Source Review Enforcement Initiative—In 1998 the EPA announced its New Source Review Enforcement Initiative targeting coal-fired power plants, petroleum refineries, pulp and paper mills and other industries for alleged violations of the EPA's New Source Review rules. These rules require owners or operators that construct new major sources or make major modifications to existing sources to obtain permits and install air pollution control equipment at affected facilities. Pursuant to the Initiative, the EPA has attempted to determine if emission sources violated certain provisions of the CAA by making major modifications to their facilities without installing state-of-the-art pollution controls. OTP has not received any recent requests from the EPA, pursuant to Section 114(a) of the CAA, to provide information relative to past operation and capital construction projects at its coal-fired plants.

Air Quality – Regional Haze Program—The CAA establishes a national visibility goal to prevent any future, and remedy any existing, anthropogenic visibility impairment in Class I air quality areas. The EPA's Regional Haze Rule (RHR), as adopted in 1999 and revised most recently on January 10, 2017, implements the CAA's visibility protection provisions. The RHR requires states to determine the consistent rate of progress over time necessary to attain natural visibility conditions on the twenty percent most anthropogenically impaired days by the year 2064. The first RHR implementation period covered the years 2008-2018 and focused on applying Best Available Retrofit Technology (BART) to certain large stationary sources that were in existence on August 7, 1977 but were not in operation before August 7, 1962. Big Stone Plant was determined to be subject to BART, and therefore was required to install Selective Catalytic Reduction and separated over-fire air to reduce NOx emissions, dry flue gas desulfurization to reduce SO2 emissions, and a new baghouse for particulate matter control. The Big Stone Plant compliant AQCS equipment was placed into commercial operation on December 29, 2015. Coyote Station is not a BART-eligible source but was ultimately required to install separated over-fire air to reduce NOx emissions as a reasonable progress source.

The second RHR implementation period will cover the years 2018-2028, with state implementation plans (SIPs) due to be submitted to EPA by July 31, 2021. For this second period, states are required to assess reasonable progress with the RHR and determine whether additional emission reductions are needed. As part of this assessment, the North Dakota Department of Health requested that Coyote Station provide an analysis of technically feasible SO_2 and NO_x emissions control options, which OTP provided in January 2019. EPA is continuing to develop other implementation tools that will be needed by states for the second period, including producing 2028 visibility modeling results, estimating international source contributions, and developing updated guidance on SIP development. Therefore, additional control measures and related costs required at Coyote Station for the second RHR implementation period remain uncertain but could be material.

Air Quality – Greenhouse Gas (GHG) Regulation—Combustion of fossil fuels for the generation of electricity is a considerable stationary source of CO_2 emissions in the United States and globally. OTP is an owner or part-owner of three baseload, coal-fired electricity generating plants and three fuel-oil or natural gas-fired combustion turbine peaking plants with a combined net dependable capacity of 650 MW. In 2018 these plants emitted approximately 3.7 million (short) tons of CO_2.

In April 2007, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate CO_2 and other GHGs from automobiles as “air pollutants” under the CAA. The EPA thereafter conducted a rulemaking to determine whether GHG emissions contribute to climate change “which may reasonably be anticipated to endanger public health or welfare.” While this case addressed a provision of the CAA related to emissions from motor vehicles, a parallel provision of the CAA applies to stationary sources such as electric generators. The EPA determined that parallel provision would be automatically triggered once the EPA began regulating motor vehicle GHG emissions. The first step in the EPA rulemaking process was the publication of an endangerment finding in the December 15, 2009 Federal Register where the EPA found that CO_2 and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride (SF_6) threaten public health and the environment.

The EPA’s endangerment finding for GHGs did not in and of itself impose any emission reduction requirements but rather authorized the EPA to finalize the GHG standards for new light-duty vehicles as part of the joint rulemaking with the Department of Transportation. These standards applied to motor vehicles as of January 2011, which the EPA determined made GHGs “subject to regulation” under the CAA. According to the EPA, this triggered the Prevention of Significant Deterioration (PSD) and Title V operating permits programs for stationary sources of GHGs. OTP does not anticipate making modifications that would trigger PSD requirements at any of its facilities or undertaking construction of a new unit that might trigger PSD.

The EPA has developed New Source Performance Standards (NSPS) for GHGs from new and existing fossil fuel-fired electric generating units. On October 23, 2015 the EPA published NSPS under section 111(b) of the CAA that require certain new units (as well as modified and reconstructed units) to meet CO_2 emission standards. New natural gas combustion turbines are required to meet a standard of 1,000 lbs. of CO_2 per gross megawatt hour averaged over a 12-month period if they meet the definition of a baseload unit. New natural gas combined cycle units are anticipated to fit into this category. Simple cycle combustion turbines are regulated in a non-baseload category that is required to meet a heat input-based standard that can be met by burning cleaner fuels such as natural gas. On December 20, 2018 the EPA proposed revisions to the 2015 NSPS; however, the revisions would only impact the standards for new, reconstructed, and modified coal or coal-refuse steam generating units. No changes are being proposed to the NSPS for natural gas combustion turbines.

GHG performance standards for existing sources are being developed under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike those set under CAA Section 111(b), applies to existing sources of a pollutant. Under Section 111(d), the EPA promulgates emission guidelines and the states are then given a period of time to develop plans to implement the standard. The EPA reviews each state-developed standard and then approves it if the state's plan comports with the federal emission guidelines. If the state does not submit a plan or the EPA finds that the plan is inadequate, the EPA will prescribe a plan for that state.

For both new and existing sources, the EPA must develop a "standard of performance" that limits the emission of air pollutants using what the EPA determines to be the best system of emission.

For existing sources, Section 111(d) also requires the EPA to consider, "among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."

On October 23, 2015 the EPA published Section 111(d) emission guidelines for existing fossil fuel-fired power plants, termed the Clean Power Plan (CPP). The CPP used a formula to calculate state goals that relied on three building blocks: (1) a heat rate improvement at each coal plant, (2) increased reliance on natural gas combined cycle units, and (3) increased deployment of renewable energy. These building blocks were applied to each grid interconnection that resulted in final national uniform emission rate standards of 1,305 pounds of CO_2 per net megawatt hour for coal plants and 771 pounds of CO_2 per net megawatt hour for natural gas combined cycle plants. The EPA then translated the rate goals into mass-based goals that can be applied to existing sources or, if a state chooses, a mass-based goal that applies to both existing sources and new sources.

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A number of states, utilities, and trade groups filed petitions for review with the D.C. Circuit seeking to overturn the rule, and also moved to stay the rule. On January 14, 2016 the D.C. Circuit denied the stay motions. Numerous petitioners then sought an emergency stay in the U.S. Supreme Court. On February 9, 2016 the U.S. Supreme Court granted a stay of the CPP, pending disposition of petitions for review in the D.C. Circuit. The D.C. Circuit heard oral argument on challenges to the CPP on September 27, 2016 before the full court, and a decision was expected in the first half of 2017. However, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, the EPA was directed to consider suspending, revising or rescinding the CO2 rules discussed above. Thereafter, the EPA issued notices of its intent to review these rules pursuant to the Executive Order, and it filed motions to stay the pending litigation. The D.C. Circuit subsequently issued orders holding in abeyance the appeals of both the NSPS and the CPP, pending EPA review. On August 21, 2018 the EPA proposed a replacement for the CPP -- the ACE Rule. Among other things, the ACE Rule determines that the best system of emission reduction for greenhouse gas emissions from coal-fired power plants are heat rate improvement measures, identifies a list of “candidate technologies” for improving a plant’s heat rate, and proposes changes to the New Source Review program. OTP submitted comments on the ACE Rule and it is anticipated that a final rule will be issued in 2019.

Several states and regional organizations have or will develop state-specific or regional legislative initiatives to reduce GHG emissions through mandatory programs. In 2007 the state of Minnesota passed legislation regarding renewable energy portfolio standards that requires retail electricity providers to obtain 25% of the electric energy sold to Minnesota customers from renewable sources by the year 2025. Additionally, in 2013 the state of Minnesota passed a provision that requires public utilities to generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5% of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy. The Minnesota legislature set a January 1, 2008 deadline for the MPUC to establish an estimate of the likely range of costs of future CO2 regulation on electricity generation. The legislation also set state targets for reducing fossil fuel use, included goals for reducing the state's output of GHGs, and restricted importing electricity that would contribute to statewide power sector CO2 emission. The MPUC, in its order dated December 21, 2007, established an estimate of future CO2 regulation costs at between $4.00 per ton and $30.00 per ton emitted in 2012 and after. Annual updates of the range are required. For 2018 and 2019 the range is $5 to $25 per ton, and the applicable effective date to begin using CO2 costs in resource planning decisions is 2025.

In 2013, Minnesota opened a new docket to investigate the environmental and socioeconomic costs of externalities associated with electricity generation. This docket studied the impact of CO2 and certain criteria pollutants. The costs are updated periodically. The most recent order was issued on January 3, 2018. The environmental cost values for CO2 range from a low of $8.44 per ton and a high of $39.76 per ton in 2017 to a low of $15.20 per ton and a high of $69.48 per ton in 2050. Low, medium, and high values were also set for various criteria pollutants for rural, metropolitan fringe, and urban areas in the state.

The states of North Dakota and South Dakota currently have no proposed or pending legislation related to the regulation of GHG emissions, but North Dakota and South Dakota have 10% renewable energy objectives. OTP currently has sufficient renewable generation to meet the renewable energy objectives in both North Dakota and South Dakota.

While the eventual outcome of GHG regulation is unknown, OTP is taking steps to reduce its carbon footprint and mitigate levels of CO_2 emitted in the process of generating electricity for its customers through the following initiatives:

Supply efficiency and reliability: Since 2005, SO_2, NO_x and mercury emitted from OTP's fossil fuel-fired plants have decreased 42%, 69% and 80%, respectively. OTP's efforts to increase plant efficiency and add renewable energy to its resource mix have reduced its CO_2 intensity. Between 2005 and 2018 OTP decreased its overall system average CO_2 emissions intensity by approximately 21%. Further reductions are expected with the planned addition of the Merricourt Wind Project and replacement of Hoot Lake Plant generation with the Astoria Station natural gas-fired generation plant in the 2021 timeframe.

Conservation: Since 1992 OTP has helped its customers conserve more than 4.7 million cumulative megawatt-hours of electricity, which is roughly equivalent to the amount of electricity that 398,500 average homes would use in a year and represents approximately 389% of the annual energy sales of OTP's entire residential customer base.

Renewable energy: Since 2002, OTP's customers have been able to purchase 100% of their electricity from wind generation through OTP's Tail Winds program. OTP has access to 102.9 MW of wind powered generation under power purchase agreements and owns 138 MW of wind powered generation. Minnesota's legislative mandate requires investor-owned utilities to serve 1.5% of their Minnesota retail electric sales with solar power by 2020. OTP has purchased sufficient SRECs to meet 100% of its 2020 obligation and approximately 70% of its 2021 obligation. OTP is exploring options for constructing a solar project to meet its continuing obligation after 2021.

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Other: OTP is a participating member of the EPA's SF6 Emission Reduction Partnership for Electric Power Systems program, which proactively is targeting a reduction in emissions of SF6, a potent GHG. SF6 has a global-warming potential 23,900 times that of CO2. OTP participates in carbon sequestration research through the Plains CO2 Reduction Partnership through the University of North Dakota's Energy and Environmental Research Center. This Partnership is a collaborative effort of approximately 100 public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic CO2 emissions from stationary sources in central North America.

While the future financial impact of any proposed or pending litigation or regulation of GHG or other emissions is unknown at this time, any capital and operating costs incurred for additional pollution control equipment or emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset credits, or the imposition of a carbon tax or cap and trade program at the state or federal level could materially adversely affect the Company's future results of operations, cash flows, and possibly financial condition, unless such costs could be recovered through regulated rates and/or future market prices for energy.

Water Quality—The Federal Water Pollution Control Act Amendments of 1972, now known as the Clean Water Act, and amendments thereto, provide for, among other things, the imposition of effluent limitations to regulate discharges of pollutants, including thermal discharges, into the waters of the United States, and the EPA has established effluent guidelines for the steam electric power generating industry. Discharges must also comply with state water quality standards.

Effluent limits specific to Hoot Lake Plant and Coyote Station are incorporated into their National Pollutant Discharge Elimination System (NPDES) permits. Big Stone Plant is a zero-discharge facility and therefore does not have a NPDES permit. On November 3, 2015 the EPA published the final rule that sets technology-based effluent limitations on certain types of discharges. Generally, the final rule establishes new requirements for wastewater streams from wet flue gas desulfurization, fly ash transport, and bottom ash transport. This includes zero discharge requirements for fly ash and bottom ash transport water. OTP's facilities either utilize dry ash handling or use transport water in a closed loop manner. Therefore, OTP anticipates minimal impact from the rule.

On May 9, 2014 the EPA Administrator signed a final rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. The final rule includes seven compliance options, plus a potential "*de minimis*" option that is not well defined. Although the impact of the Hoot Lake Plant intake structure has been extensively evaluated in two separate studies both of which showed minimal impact, OTP will need to have state agency discussions during the renewal of the Hoot Lake Plant NPDES permit to determine the appropriate path forward. Coyote Station's NPDES permit was renewed in 2018 with minimal impact since Coyote Station already uses closed-cycle cooling. OTP has all federal and state water permits presently necessary for the operation of the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

OTP owns five small dams on the Otter Tail River, which are subject to FERC licensing requirements. A license for all five dams was issued on December 5, 1991. In June 2015 OTP notified the FERC of its intent to relicense these dams. The current FERC license expires in 2021 and the licensing process takes approximately 5 years. The FERC completed the scoping meeting in the fall of 2016 and issued a study plan determination in April 2017. OTP completed the first round of studies in 2017 and a second round in 2018. These studies will be followed by the filing of the license application in 2019. OTP expects the FERC to issue an order on the license application in 2021. Total nameplate rating (manufacturer's expected output) of the five dams is 3,250 kW.

Solid Waste—Permits for disposal of ash and other solid wastes have been issued for the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

On December 19, 2014 the EPA announced a final rule regulating coal combustion residuals (CCR) under the Resource Conservation and Recovery Act regulating the disposal of coal ash generated from the combustion of coal by electric utilities under Subtitle D's nonhazardous provisions. The rule has required OTP to complete certain actions, such as installing additional groundwater monitoring wells and investigating whether existing surface impoundments should be retired or retrofitted with liners. The Big Stone Plant surface impoundment was closed by removing all CCR material and replaced with new ash handling technology in 2018. A similar project is expected to be completed at Coyote Station in 2019. Existing landfill cells can continue to operate as designed, but future expansions may require composite liner and leachate collection systems. On December 20, 2016 the Water Infrastructure Improvements for the Nation (WIIN) Act was signed into law. The WIIN Act allows states to regulate CCR if the state standards are at least as protective as the EPA CCR Rule. North Dakota and South Dakota have indicated they plan to incorporate the CCR rule, but that it will take a multi-year process.

At the request of the MPCA, OTP had an ongoing investigation at its former, closed Hoot Lake Plant ash disposal sites. The MPCA continues to monitor site activities under its Voluntary Investigation and Cleanup Program. OTP completed projects in 2014 through 2017 that removed the ash in its entirety from all four Voluntary Investigation and Cleanup Program areas and placed it in OTP's permitted disposal area.

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In 1980 the United States enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly known as CERCLA or the Federal Superfund law, which was reauthorized and amended in 1986. In 1983 Minnesota adopted the Minnesota Environmental Response and Liability Act, commonly known as the Minnesota Superfund law. In 1988 South Dakota enacted the Regulated Substance Discharges Act, commonly known as the South Dakota Superfund law. In 1989, North Dakota enacted the Environmental Emergency Cost Recovery Act. Among other requirements, the federal and state acts establish environmental response funds to pay for remedial actions associated with the release or threatened release of certain regulated substances into the environment. These federal and state Superfund laws also establish liability for cleanup costs and damage to the environment resulting from such release or threatened release of regulated substances. The Minnesota Superfund law also creates liability for personal injury and economic loss under certain circumstances. OTP has not incurred any significant costs to date related to these laws. OTP is not presently named as a potentially responsible party under the federal or state Superfund laws.

Capital Expenditures

In order to meet customer needs, OTP is continually expanding, replacing and improving its electric facilities. During 2018 approximately $87 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2018 gross electric property additions, including CWIP, were approximately $635 million and gross retirements were approximately $90 million. OTP estimates that during the five-year period 2019-2023 it will invest approximately $973 million for electric construction, including:

- $348 million for renewable wind and solar energy generation and conservation, including the Merricourt Wind Project scheduled for completion in 2020, the exercise of a purchase option on the Ashtabula III wind farm in 2022, a major investment in solar generation in 2022 and routine wind-power replacement projects.

- $150 million for the Astoria natural gas-fired generation plant to replace Hoot Lake Plant capacity.

- $145 million for numerous potential technology and infrastructure projects to transform future operations, including automated metering, telecommunications, geographic information systems, work and asset management systems, financial information systems, system infrastructure reliability improvements, outage management systems, and storage projects.

- $122 million for transmission assets including new construction and routine replacement projects. New construction includes $7.8 million for the completion of the Big Stone South–Ellendale line in 2019.

The remaining $208 million of the 2019-2023 anticipated capital expenditures is for asset replacements, additions and improvements to OTP’s other generation, distribution and general plant. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Capital Requirements” section for further discussion.

Franchises

At December 31, 2018 OTP had franchises to operate as an electric utility in substantially all of the incorporated municipalities it serves. All franchises are nonexclusive and generally were obtained for 20-year terms, with varying expiration dates. No franchises are required to serve unincorporated communities in any of the three states that OTP serves. OTP believes that its franchises will be renewed prior to expiration.

Employees

At December 31, 2018 OTP had 669 equivalent full-time employees. A total of 394 OTP employees are represented by local unions of the International Brotherhood of Electrical Workers under two separate contracts expiring on August 31, 2020 and October 31, 2020. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

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MANUFACTURING

General

Manufacturing consists of businesses engaged in the following activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components.

The Company derived 29%, 27% and 28% of its consolidated operating revenues and 14%, 11% and 11% of its consolidated operating income from the Manufacturing segment for the years ended December 31, 2018, 2017 and 2016, respectively. Following is a brief description of each of these businesses:

BTD Manufacturing, Inc. (BTD), with headquarters located in Detroit Lakes, Minnesota, is a metal stamping and tool and die manufacturer that provides its services mainly to customers in the Midwest. BTD stamps, fabricates, welds, paints and laser cuts metal components according to manufacturers' specifications primarily for the recreational vehicle, agricultural, oil and gas, lawn and garden, industrial equipment, health and fitness and enclosure industries in its facilities in Detroit Lakes and Lakeville, Minnesota, Washington, Illinois and Dawsonville, Georgia. BTD's Illinois facility also manufactures and fabricates parts for off-road equipment, mining machinery, oil fields and offshore oil rigs, wind industry components, broadcast antennae and farm equipment. BTD-Georgia offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers.

T.O. Plastics, Inc. (T.O. Plastics), located in Otsego and Clearwater, Minnesota, manufactures and sells thermoformed products for the horticulture industry throughout the United States. T.O. Plastics also designs and manufactures quality thermoformed products and packaging solutions for the medical and life sciences, industrial, recreation and electronics industries. Examples of products produced for these industries are clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts.

Product Distribution

The principal method for distribution of the manufacturing companies' products is by direct shipment to the customer by common carrier ground transportation. No single customer or product of the Company's manufacturing companies accounted for 10% of the Company's consolidated revenue. However, the top two customers combined accounted for 33% and the top five customers combined accounted for over 52% of 2018 Manufacturing segment revenue.

Competition

The various markets in which the Manufacturing segment entities compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources, excess capacity, labor advantages and larger marketing, research and development staffs and facilities than the Company’s manufacturing entities.

The Company believes the principal competitive factors in its Manufacturing segment are product performance, quality, price, technical innovation, cost effectiveness, customer service and breadth of product line. The Company’s manufacturing entities intend to continue to compete based on high-performance products, innovative production technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

Raw Materials Supply

The companies in the Manufacturing segment use raw materials in the products they manufacture, including steel, aluminum and polystyrene and other plastics resins. Both pricing increases and availability of these raw materials are concerns of companies in the Manufacturing segment. The companies in the Manufacturing segment attempt to pass increases in the costs of these raw materials on to their customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins in the Manufacturing segment. Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes used by the Company’s manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of the Company’s manufacturing companies as it reduces their ability to mitigate the cost associated with excess material.

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Backlog

The Manufacturing segment has backlog in place to support 2019 revenues of approximately $211 million compared with $166 million one year ago.

Capital Expenditures

Capital expenditures in the Manufacturing segment typically include additional investments in new manufacturing equipment or expenditures to replace worn-out manufacturing equipment. Capital expenditures may also be made for the purchase of land and buildings for plant expansion and for investments in management information systems. During 2018, cash expenditures for capital additions in the Manufacturing segment were approximately $13 million. Total capital expenditures for the Manufacturing segment during the five-year period 2019-2023 are estimated to be approximately $77 million.

Employees

At December 31, 2018 the Manufacturing segment had 1,445 full-time employees. There were 1,273 full-time employees at BTD and 172 full-time employees at T.O. Plastics as of December 31, 2018.

PLASTICS

General

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The Company derived 22%, 22% and 19% of its consolidated operating revenues and 25%, 22% and 16% of its consolidated operating income from the Plastics segment for the years ended December 31, 2018, 2017 and 2016, respectively. Following is a brief description of these businesses:

Northern Pipe Products, Inc. (Northern Pipe), located in Fargo, North Dakota, manufactures and sells PVC pipe for municipal water, rural water, wastewater, storm drainage systems and other uses in the northern, midwestern, south-central and western regions of the United States as well as central and western Canada.

Vinyltech Corporation (Vinyltech), located in Phoenix, Arizona, manufactures and sells PVC pipe for municipal water, wastewater, water reclamation systems and other uses in the western, northwest and south-central regions of the United States.

Together these companies have the current capacity to produce approximately 300 million pounds of PVC pipe annually.

Customers

PVC pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for the PVC pipe products consist primarily of wholesalers and distributors throughout the northern, midwestern, south-central, western and northwest United States. The principal method for distribution of the PVC pipe companies' products is by common carrier ground transportation. No single customer of the PVC pipe companies accounts for over 10% of the Company's consolidated revenue. However, two customers combined accounted for 39% of 2018 Plastics segment revenue.

Competition

The plastic pipe industry is fragmented and competitive due to the number of producers, the small number of raw material suppliers and the fungible nature of the product. Due to shipping costs, competition is usually regional, instead of national, in scope. The principal factors of competition are price, service, warranty, and product performance. Northern Pipe and Vinyltech compete not only against other plastic pipe manufacturers, but also ductile iron, steel and concrete pipe producers. Pricing pressure will continue to affect our Plastics segment operating margins in the future.

Northern Pipe and Vinyltech intend to continue to compete based on their high-quality products, cost-effective production techniques and close customer relations and support.

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Manufacturing and Resin Supply

PVC pipe is manufactured through a process known as extrusion. During the production process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is then pulled through a series of water-cooling tanks, marked to identify the type of pipe and cut to finished lengths. Warehouse and outdoor storage facilities are used to store the finished product. Inventory is shipped from storage to distributors and customers by common carrier.

The PVC resins are acquired in bulk and shipped to point of use by rail car. There are three vendors that Northern Pipe and Vinyltech can source to supply their PVC resin requirements. Two vendors provided over 99% of total resin purchases in 2018 and 100% in 2017. The supply of PVC resin may also be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region, which is subject to risk of damage to the plants and potential shutdown of resin production because of exposure to hurricanes that occur in that part of the United States. In 2017, Hurricane Harvey caused major resin suppliers in the Gulf Coast region to shut down production facilities impacting raw material availability. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could disrupt the ability of the Plastics segment to manufacture products, cause customers to cancel orders or require incurrence of additional expenses to obtain PVC resin from alternative sources, if such sources were available. Both Northern Pipe and Vinyltech believe they have good relationships with their key raw material vendors.

Due to the commodity nature of PVC resin and PVC pipe and the dynamic supply and demand factors worldwide, historically the markets for both PVC resin and PVC pipe have been very cyclical with significant fluctuations in prices and gross margins.

Capital Expenditures

Capital expenditures in the Plastics segment typically include investments in extrusion machines and support equipment. During 2018, cash expenditures for capital additions in the Plastics segment were approximately $4 million. Total capital expenditures for the five-year period 2019-2023 are estimated to be approximately $20 million to replace existing equipment.

Employees

At December 31, 2018 the Plastics segment had 170 full-time employees. Northern Pipe had 100 full-time employees and Vinyltech had 70 full-time employees as of December 31, 2018.

Item 1A. RISK FACTORS

RISK FACTORS AND CAUTIONARY STATEMENTS

Our businesses are subject to various risks and uncertainties. Any of the risks described below or elsewhere in this Annual Report on Form 10-K or in our other SEC filings could materially adversely affect our business, financial condition and results of operations.

GENERAL

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

We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements requires us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

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

We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are unable to access capital at competitive rates, our ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more financial markets.

Borrowings under our $130 million revolving credit agreement and OTP’s $170 million revolving credit agreement currently use LIBOR as the base to determine the applicable interest rate to charge. LIBOR is currently expected to be eliminated by January 1, 2022. The credit agreements contain provisions to determine how interest rates will be established in the event a replacement for LIBOR has not been identified before the agreements expire on October 31, 2023. There is no assurance that the replacement for LIBOR will be as favorable as LIBOR.

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

Changes in the U.S. capital markets could also have significant effects on our pension plan. Our pension income or expense is affected by factors including the market performance of the assets in the master pension trust maintained for the pension plan for some of our employees, the weighted average asset allocation and long-term rate of return of our pension plan assets, the discount rate used to determine the service and interest cost components of our net periodic pension cost and assumed rates of increase in our employees’ future compensation. If our pension plan assets do not achieve positive rates of return, or if our estimates and assumed rates are not accurate, our earnings may decrease because net periodic pension costs would rise and we could be required to provide additional funds to cover our obligations to employees under the pension plan.

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

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

We had approximately $37.6 million of goodwill recorded on our consolidated balance sheet as of December 31, 2018. We have recorded goodwill for businesses in our Manufacturing and Plastics business segments. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net operating performance. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying amount of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Any changes in key assumptions or actual performance compared with key assumptions about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge. Declines in projected operating cash flows at BTD or the Plastics segment may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

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

Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the actual and projected earnings, cash flows, capital requirements and general financial position of our subsidiary companies, as well as regulatory factors, financial covenants, general business conditions and other matters.

Under our $130 million revolving credit agreement we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00. OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 under its $170 million revolving credit agreement. Both credit agreements contain restrictions on the payment of cash dividends on a default or event of default. As of December 31, 2018, we were in compliance with the debt covenants.

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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 Otter Tail Corporation by requiring an equity-to-total-capitalization ratio between 47.9% and 58.5% based on OTP's 2018 capital structure petition. OTP's equity-to-total-capitalization ratio, including short-term debt, was 53.2% as of December 31, 2018.

While these restrictions are not expected to affect our ability to pay dividends at the current level in the foreseeable future, there is no assurance that adverse financial results would not reduce or eliminate our ability to pay dividends.

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.

The operation of our business is dependent on the secure function of our computer hardware and software systems. Furthermore, all our businesses require us to collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss. We also use third-party vendors to electronically process certain of our business transactions. Information systems, both ours and those of third parties, are vulnerable to security breach by computer hackers and cyber terrorists, and the negligent or intentional breach of established controls and procedures or mismanagement of confidential information by employees. We may also be impacted by attacks and data security breaches of financial institutions, merchants or third-party processors. While we regularly conduct cybersecurity assessments, we cannot be certain our information security systems and protocols and those of our vendors and other third parties are sufficient to withstand a cyber-attack or other security breach.

The breach of certain business systems could affect our ability to correctly record, process and report financial information and transactions. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For example, we may be subject to liability under various federal, state and international data protections laws.

The misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant monetary damages, regulatory enforcement actions and breach notification and mitigation expenses such as credit monitoring and result in reputational damage affecting relations with shareholders, customers and regulators. We have cybersecurity insurance related to a breach event covering expenses for notification, credit monitoring, investigation, crisis management, public relations and legal advice. The policy also provides coverage for regulatory action defense including fines and penalties, potential payment card industry fines and penalties and costs related to cyber extortion. We also maintain property and casualty insurance that may cover restoration of data, certain physical damage or third-party injuries caused by potential cybersecurity incidents. However, damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available.

We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information maintained on our information systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls designed to protect and preserve the confidentiality, integrity and availability of data and systems and we have adopted a disaster recovery plan. Additionally, we've taken steps to increase cybersecurity awareness among our employees through mandatory education and training programs and through informational communications on potential security threats and techniques used by hackers and cyber criminals. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks or enable us to recover effectively from such an attack. In addition, the unavailability of the information systems or failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance and increased overhead costs, causing our business and results of operations to suffer. Any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches could adversely affect our business and results of operations.

Like many other companies, we have been the target of malicious cyber-attack attempts in the normal course of business. Although these prior cyber-attacks have been limited in scope, have not interrupted our business operations and have not had a material impact on our financial results, this may not continue to be the case in the future. Cybersecurity incidents involving businesses and other institutions are on the rise, we believe these incidents are likely to continue and we are unable to predict the direct or indirect impact of future attacks or breaches to our business.

Economic conditions could negatively impact our businesses.

Our businesses are affected by local, national and worldwide economic conditions. Tightening of credit in financial markets could adversely affect the ability of customers to finance purchases of our goods and services, resulting in decreased orders, cancelled or deferred orders, slower payment cycles, and increased bad debt and customer bankruptcies. Our businesses may also be adversely affected by decreases in the general level of economic activity, such as decreases in business and consumer spending. A decline in the level of economic activity and uncertainty regarding energy and commodity prices could adversely affect our results of operations and our future growth.

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

We expect much of our growth in the next few years will come from major capital investment at existing companies. To achieve the organic growth we expect, we must have access to the capital markets, be successful with capital expansion programs related to organic growth, develop new products and services, expand our markets and increase efficiencies in our businesses. Competitive and economic factors could adversely affect our ability to do this. If we are unable to achieve and sustain consistent organic growth, we will be less likely to meet our revenue growth targets, which, together with any resulting impact on our net income growth, may adversely affect the market price of our common shares.

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.

As part of our business strategy, we intend to increase capital expenditures in our existing businesses and to continually assess our mix of businesses and potential strategic acquisitions or dispositions. There are risks associated with capital expenditures including not being granted timely or full recovery of rate base additions in our regulated utility business, the inability to recover the cost of capital additions due to an economic downturn, not being granted timely approval of requested interconnections to the transmission system for planned generation projects, lack of markets for new products, competition from producers of lower cost or alternative products, product defects, loss of customers or other factors. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. Future acquisitions could involve numerous risks including: difficulties in integrating the operations, services, products and personnel of the acquired business; and the potential loss of key employees, customers and suppliers of the acquired business. If we are unable to successfully manage these risks, we could face reductions in net income in future periods.

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 also exposes us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.

As part of our business strategy, we continually assess our business portfolio to determine if our operating companies continue to meet our portfolio criteria. A loss on the sale of a business would be recognized if a company is sold for less than its book value.

In certain transactions we retain obligations that have arisen, or subsequently arise, out of our conduct of the business prior to the sale. These obligations are sometimes direct or, in other cases, take the form of an indemnification obligation to the buyer. These obligations include such things as warranty, environmental, and the collection of certain receivables. Unforeseen costs related to these obligations could result in future losses related to the business sold.

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.

Depending on the specific product or service, we may provide certain warranty terms against manufacturing defects and certain materials. We reserve for warranty claims based on industry experience and estimates made by management. For some of our products we have limited history on which to base our warranty estimate. Our assumptions could be materially different from any actual claim and could exceed reserve balances.

Expenses associated with the remediation of warranty claims for our manufacturing businesses, including our former wind tower manufacturer, could be substantial. The potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. If we are required to cover remediation expenses in addition to our regular warranty coverage, we could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect our consolidated net income and financial condition.

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We are subject to risks associated with energy markets.

Our businesses are subject to the risks associated with energy markets, including market supply and increasing energy prices. If we are faced with shortages in market supply, we may be unable to fulfill our contractual obligations to our retail, wholesale and other customers at previously anticipated costs. This could force us to obtain alternative energy or fuel supplies at higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher than expected energy or fuel costs would negatively affect our financial performance.

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.

Our provision for income taxes and reporting of tax-related assets and liabilities require significant judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, regulations and interpretations, the financial condition and results of operations of the Company, and the resolution of audit issues raised by taxing authorities. Ultimate resolution of income tax matters may result in material adjustments to tax-related assets and liabilities, which 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 the Company.

While no single customer of the Company provides more than 10% of consolidated revenue, each of the Company’s segments have large customers that provide over 10% of the operating company’s and its segment’s revenue. In 2018 one customer accounted for 11% of Electric segment revenue, two customers accounted for a total of 33% of Manufacturing segment revenue and two customers accounted for 39% of Plastics segment revenue. The loss of any one of these customers, or a significant decline in sales to these customers, would have a significant negative impact on the operating company’s and its business segment’s financial position and results of operations, and could have a significant negative impact on the Company’s consolidated financial position and results of operations.

ELECTRIC

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.

Several factors, many of which are beyond our control, may contribute to fluctuations in our revenues and expenses from electric operations, causing our net income to fluctuate from period to period. These risks include fluctuations in the volume and price of sales of electricity to customers or other utilities, which may be affected by factors such as mergers and acquisitions of other utilities, geographic location of other utilities, transmission costs (including increased costs related to operations of regional transmission organizations), interconnection costs, changes in the manner in which wholesale power is sold and purchased, unplanned interruptions at OTP’s generating plants, the effects of regulation and legislation, demographic changes in OTP’s customer base and changes in OTP’s customer demand or load growth. Other risks include weather conditions or changes in weather patterns (including severe weather that could result in damage to OTP’s assets), fuel and purchased power costs and the rate of economic growth or decline in OTP’s service areas. A decrease in revenues or an increase in expenses related to our electric operations may reduce the amount of funds available for our existing and future utility business, which could result in increased financing requirements, impair our ability to make expected distributions to shareholders or impair our ability to make scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

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

We are subject to federal and state legislation, government regulations and regulatory actions that may have a negative impact on our business and results of operations. The electric rates that OTP is allowed to charge for its electric services are one of the most important items influencing our financial position, results of operations and liquidity. The rates that OTP charges its electric customers are subject to review and determination by state public utility commissions in Minnesota, North Dakota and South Dakota. OTP is also regulated by the FERC. Our ability to obtain rate adjustments to maintain reasonable rates of return depends on regulatory action under applicable statutes and regulations and we cannot provide assurance that rate adjustments will be obtained or reasonable authorized rates of return on capital will be earned. OTP will file rate cases with, or seek cost recovery authorization from, federal and state regulatory authorities. An adverse decision by one or more regulatory commissions concerning the level or method of determining electric utility rates, the authorized returns on equity, implementation of enforceable federal reliability standards or other regulatory matters, permitted business activities (such as ownership or operation of nonelectric businesses) or any prolonged delay in rendering a decision in a rate or other proceeding (including with respect to the recovery of capital expenditures in rates) could result in lower revenues and net income.

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

We are subject to an extensive legal and regulatory framework imposed under federal and state law and regulatory agencies, including FERC and NERC. We could be subject to potential financial penalties for compliance violations. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. If a serious reliability incident did occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance. We attempt to mitigate the risk of regulatory penalties through formal training. However, there is no guarantee our compliance program will be sufficient to ensure against violations.

In addition, energy policy initiatives at the state or federal level could increase incentives for distributed generation or authorize municipal utility formation or acquisition of service territory, or local initiatives could introduce generation or distribution requirements that could change the current integrated utility model.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary approvals for our existing operations and that our business is conducted in accordance with applicable laws and regulatory requirements; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations or the imposition of additional regulations could have a material adverse impact on our results of operations.

OTP’s 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.

OTP owns electric transmission and generation facilities subject to mandatory and enforceable standards advanced by the NERC. These bulk electric system facilities provide the framework for the electrical infrastructure of OTP’s service territory and interconnected systems, the operation of which is dependent on information technology systems. Further, the information systems that operate OTP’s electric system are interconnected to external networks. Parties that wish to disrupt the U.S. bulk power system or OTP’s operations could view OTP’s computer systems, software or networks as attractive targets for cyber-attack.

In addition, OTP’s generation and transmission facilities are spread throughout a large service territory. These facilities could be subject to physical attack or vandalism that could disrupt OTP’s operations or conceivably the regional or U.S. bulk power system.

OTP is subject to mandatory cybersecurity and physical security regulatory requirements. OTP implements the NERC standards for operating its transmission and generation assets and stays abreast of best practices within business and the utility industry to protect its computers and computer-controlled systems from outside attack. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information necessary for the operation of our systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls and a disaster recovery plan designed to protect and preserve the confidentiality, integrity and availability of data and systems. We also take prudent and reasonable steps to protect the physical security of our generation and transmission facilities. FERC has approved Version 5 of the Critical Infrastructure Protection Cybersecurity Standards. The standards

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require us to categorize our cyber assets as high, medium and low impact. As of December 31, 2018, all of these cyber assets were in compliance with the standard. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks or enable us to recover effectively from such a breach or attack. Any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches or physical attack of our generation or transmission facilities could adversely affect our business and results of operations.

Like many other companies, we have been the target of malicious cyber-attack attempts in the normal course of business. Although these prior cyber-attacks have been limited in scope, have not interrupted our business operations and have not had a material impact on our financial results, this may not continue to be the case in the future. Cybersecurity incidents involving businesses and other institutions are on the rise, we believe these incidents are likely to continue and we are unable to predict the direct or indirect impact of future attacks or breaches to our business.

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

Operation of electric generating facilities involves risks which can adversely affect energy output and efficiency levels. Most of OTP's generating capacity is coal-fired. OTP relies on a limited number of suppliers of coal, making it vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. OTP is a captive rail shipper of the BNSF Railway for shipments of coal to its Big Stone and Hoot Lake plants, making it vulnerable to increased prices for coal transportation from a sole supplier and disruptions in coal deliveries due to rail line congestion and constraints on the rail lines between the coal source mines and the plants. Higher fuel prices result in higher electric rates for OTP's retail customers through fuel clause adjustments and could make it less competitive in wholesale electric markets. Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error and catastrophic events such as fires, explosions, floods, intentional acts of destruction or other similar occurrences affecting OTP's electric generating facilities. The loss of a major generating facility would require OTP to find other sources of electricity for its customers, if available, and expose it to higher purchased power costs.

Changes to regulation of generating plant emissions, including but not limited to CO2 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 OTP's steam-powered electric plants.

Existing or new laws or regulations passed or issued by federal or state authorities addressing climate change or reductions of GHG emissions, such as mandated levels of renewable generation, mandatory reductions in CO2 emission levels, taxes on CO2 emissions or cap and trade regimes, could require us to incur significant new costs, which could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where OTP provides service or through increased market prices for electricity. Debate continues in Congress and in the current administration on the direction and scope of U.S. and international policy on climate change and regulation of GHGs. Congress has considered but has not adopted GHG legislation which would require a reduction in GHG emissions. The likelihood of any federal mandatory CO2 emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, are uncertain, as are the future of additional regulatory actions.

Under the previous presidential administration, the EPA published final rules for the CPP, including NSPS regulations governing GHGs from new and existing fossil fuel-fired electric generating units and GHG performance and emissions standards for existing fossil fuel-fired power plants. The CPP rule is not currently in effect as a result of a stay by the U.S. Supreme Court granted in 2016. On August 21, 2018 the EPA proposed a replacement for the CPP – the ACE Rule. Among other things, the ACE Rule determines the best system of emission reduction for greenhouse gas emissions from coal-fired power plants is to improve a plant's heat rate, identifies a list of "candidate technologies" for improving a plant's heat rate and proposes changes to the New Source Review program. The fate of the former administration's GHG rules is uncertain, as is the outcome of EPA's potential GHG regulatory actions under the current administration. The final outcome of this rulemaking process could have a material adverse impact on our business and financial results.

State implementation of pollution control plans to improve visibility and air quality at national parks under the EPA's Regional Haze Rule could require us to incur significant new costs, which could negatively impact our net income, financial position and operating cash flows. The EPA is involved in ongoing litigation with states and regulated industries regarding the adequacy of state implementation plans. However, in September 2018, the EPA's Regional Haze Reform Roadmap prioritized giving more power to states to determine emissions controls and relying on other Clean Air Act programs to improve visibility.

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In certain circumstances, it may not be economically viable to install and operate pollution control equipment at older generation facilities in order to bring them into compliance with environmental laws and regulations, including state implementation plans for the Regional Haze Rule. In those circumstances, it may be necessary to pursue replacement electric generation facilities as an alternative, which may require incurring significant investment in new facilities and recording significant asset impairment charges relating to replaced facilities, in addition to obtaining necessary regulatory permits and approvals.

MANUFACTURING

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 manufacturing businesses are subject to intense risks associated with competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development staffs and facilities and other capabilities that may place downward pressure on margins and profitability. The companies in our Manufacturing segment use a variety of raw materials in the products they manufacture, including steel, aluminum and polystyrene and other plastics resins. Costs for these items can fluctuate significantly. If our manufacturing businesses are not able to pass on cost increases to their customers, it could have a negative effect on profit margins in our Manufacturing segment. Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes used by our manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply, can negatively impact the profitability of our manufacturing companies as it reduces their ability to mitigate the cost associated with excess material. Changes in macroeconomic conditions can negatively impact demand in the end-use markets for products and parts that we manufacture, resulting in reduced sales and profits. There is no assurance the initiatives underway to increase revenues and improve margins at our manufacturing businesses will be successful.

PLASTICS

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 rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors provided over 99% of our total purchases of PVC resin in 2018 and 2017. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region, which may increase the risk of a shortage of resin in the event of a hurricane or other natural disaster in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources are available.

We compete against many other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.

The plastic pipe industry is fragmented and competitive due to the number of producers and the fungible nature of the product. We compete not only against other plastic pipe manufacturers, but also against ductile iron, steel and concrete pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope, and the principal areas of competition are a combination of price, service, warranty, and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics business.

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

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower. Changes in PVC resin prices can negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of our finished goods inventory.

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Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 2. PROPERTIES

The Coyote Station, which commenced operation in 1981, is a 414,000 kW (nameplate rating) mine-mouth plant located in the lignite coal fields near Beulah, North Dakota and is jointly owned by OTP, Northern Municipal Power Agency, Montana-Dakota Utilities Co. and Northwestern Public Service Company. OTP is the operating agent of the Coyote Station and owns 35% of the plant.

OTP, jointly with Northwestern Public Service Company and Montana-Dakota Utilities Co., owns the 414,000 kW (nameplate rating) Big Stone Plant in northeastern South Dakota which commenced operation in 1975. OTP is the operating agent of Big Stone Plant and owns 53.9% of the plant.

Located near Fergus Falls, Minnesota, the Hoot Lake Plant is comprised of two separate generating units: a unit built in 1959 (53,500 kW nameplate rating) and a unit added in 1964 (75,000 kW nameplate rating) and modified in 1988 to provide cycling capability, allowing this unit to be more efficiently brought online from a standby mode. These two generating units have a combined nameplate rating of 128,500 kW. Current plans are for both units to be retired from service in 2021.

OTP owns 27 wind turbines at the Langdon, North Dakota Wind Energy Center with a nameplate rating of 40,500 kW, 32 wind turbines at the Ashtabula Wind Energy Center located in Barnes County, North Dakota with a nameplate rating of 48,000 kW and 33 wind turbines at the Luverne Wind Farm located in Griggs and Steele Counties, North Dakota with a nameplate rating of 49,500 kW.

As of December 31, 2018, OTP's transmission facilities, which are interconnected with lines of other public utilities, consisted of 618 pole-miles of jointly owned 345 kV lines; 470 pole-miles of 230 kV lines, of which 70 miles are jointly owned; 873 pole-miles of 115 kV lines; and 3,989 pole-miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of 48 pole-miles of the 345 kV lines, with Minnkota Power Cooperative retaining title to the original 230 kV construction, and OTP owns an undivided interest in the remaining 345 kV line miles. OTP is a joint owner, with other regional utilities, in transmission lines with the following ownership interests: 14.8% in the 70 mile

Bemidji-Grand Rapids 230 kV line, approximately 14.2% of 242 pole-miles of energized line in the Fargo–Monticello 345 kV project, approximately 4.8% of 255 pole-miles of energized line in the Brookings to Southeast Twin Cities 345 kV project, and 50.0% of 72 pole-miles of energized line in the Big Stone South–Brookings 345 kV project.

In addition to the properties mentioned above, all of which are utilized by the Electric segment, the Company owns and has investments in offices and service buildings utilized by each of its manufacturing and plastic pipe companies. The Company’s subsidiaries own facilities and equipment used in: the manufacture of PVC pipe, thermoformed products, heavy metal fabricated products, metal parts stamping, fabricating, painting and contract machining.

Management of the Company believes the facilities and equipment described above are adequate for the Company's present businesses.

Item 3. LEGAL PROCEEDINGS

The Company is the subject of various pending or threatened legal actions and proceedings in the ordinary course of its business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. The Company records a liability in its consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where the Company has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes 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 its consolidated financial position, results of operations or cash flows.

Item 3A. **EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF FEBRUARY 22, 2019)**

Set forth below is a summary of the principal occupations and business experience during the past five years of the executive officers as defined by rules of the SEC. Each of the executive officers, excluding John Abbott, has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly owned subsidiary, Otter Tail Power Company.

NAME AND AGE	DATE ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
Charles S. MacFarlane (54)	4/13/15	Present:	President and Chief Executive Officer
Kevin G. Moug (59)	4/9/01	Present:	Chief Financial Officer and Senior Vice President
Timothy J. Rogelstad (52)	4/14/14	Present:	Senior Vice President, Electric Platform
John Abbott (60)	2/11/15	Present:	Senior Vice President, Manufacturing Platform
Jennifer O. Smestad (48)	1/1/18	Present:	Vice President, General Counsel and Corporate Secretary

Mr. MacFarlane was elected as the Company's President and Chief Executive Officer and as member of the Company's board of directors on April 13, 2015. Prior to that, he served as President and Chief Operating Officer of the Company, since April 14, 2014. Mr. MacFarlane joined OTP in 2001, served as its President from 2003 to 2014 and has served as its Chief Executive Officer from 2007 to the present. He served as Senior Vice President, Electric Platform of the Company from 2012 to 2014.

Kevin G. Moug has held his present positions with the Company for more than five years.

Timothy J. Rogelstad was appointed to succeed Mr. MacFarlane as President of OTP and Senior Vice President, Electric Platform of the Company on April 14, 2014. Mr. Rogelstad joined OTP in June 1989 as an engineer in the System Engineering Department and served as Supervisor, Transmission Planning, and Manager, Delivery Planning, before being named Vice President, Asset Management, in 2012. In the role of Vice President, Asset Management at OTP, he was in charge of OTP's Delivery Planning, Delivery Maintenance, Delivery Engineering, System Operations, and Project Management Departments.

John Abbott was selected to serve as Senior Vice President, Manufacturing Platform, and President of Varistar on February 5, 2015. Prior to coming to the Company, Mr. Abbott served as an officer and group vice president for eight years at Standex International Corporation (Standex), a group of restaurant equipment companies. During his last five years at Standex, Mr. Abbott served as Group Vice President, Food Service Equipment Group. In this role, Mr. Abbott was responsible for all strategic and operational aspects of the Food Service Equipment business. Prior to working at Standex, Mr. Abbott was with Pentair for 20 years, rising from product manager to president and global business unit leader of its water filtration division.

Jennifer O. Smestad was appointed to the position of Vice President, General Counsel and Corporate Secretary of the Company, effective January 1, 2018. Ms. Smestad joined the Company on May 14, 2001 as an Associate General Counsel and has served in various legal capacities of increasing responsibility at the Company and at OTP. She most recently served as General Counsel for OTP from March 1, 2013 to the present.

The term of office for each of the executive officers is one year and any executive officer elected may be removed by the vote of the board of directors at any time during the term. There are no family relationships between any of the executive officers or directors.

Item 4. Mine Safety Disclosures

Not Applicable.

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PART II

Item 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company’s common stock is traded on the Nasdaq Global Select Market under the Nasdaq symbol “OTTR”. The information required by this Item can be found on Page 39 of this Annual Report on Form 10-K under the heading “Selected Financial Data,” on Page 96 under the heading “Retained Earnings and Dividend Restriction” and on Page 117 under the heading “Supplementary Financial Information.” The Company does not have a publicly announced stock repurchase program. The Company did not repurchase any equity securities during the three months ended December 31, 2018.

PERFORMANCE GRAPH

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

This graph compares the cumulative total shareholder return on the Company’s common shares for the last five fiscal years with the cumulative return of The Nasdaq Stock Market Index and the Edison Electric Institute (EEI) Index over the same period (assuming the investment of $100 in each vehicle on December 31, 2013, and reinvestment of all dividends).

	2013	**2014**	**2015**	**2016**	**2017**	**2018**
OTC	**$100.00**	**$110.19**	**$99.12**	**$157.67**	**$177.14**	**$203.60**
EEI	**$100.00**	**$128.91**	**$123.88**	**$145.48**	**$162.52**	**$168.49**
Nasdaq	**$100.00**	**$112.46**	**$113.00**	**$127.70**	**$155.01**	**$146.57**

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Item 6. SELECTED FINANCIAL DATA

(thousands, except number of shareholders and per-share data)	**2018**	2017	2016	2015	2014
Revenues					
Electric					
Revenues from Contracts with Customers	**$450,694**	$436,508	$425,279	$410,109	$406,242
Changes in Accrued Revenues under Alternative Revenue Programs	**(439)**	(1,971)	2,104	(2,978)	1,501
Total Electric Revenues	**450,255**	434,537	427,383	407,131	407,743
Manufacturing Revenues from Contracts with Customers	**268,409**	229,738	221,289	215,011	219,583
Plastics Revenues from Contracts with Customers	**197,840**	185,132	154,901	157,758	172,050
Intersegment Eliminations – Contracts with Customers	**(57)**	(57)	(34)	(96)	(114)
Total Operating Revenues	**$916,447**	$849,350	$803,539	$779,804	$799,262
Revenues from Contracts with Customers	**$916,886**	$851,321	$801,435	$782,782	$797,761
Net Income from Continuing Operations	**$82,345**	$72,439	$62,321	$58,589	$56,883
Net Income from Discontinued Operations	**--**	--	--	756	840
Net Income	**$82,345**	$72,439	$62,321	$59,345	$57,723
Operating Cash Flow from Continuing Operations	**$143,448**	$173,577	$163,386	$131,540	$125,769
Operating Cash Flow - Continuing and Discontinued Operations	**143,448**	173,577	163,386	117,540	112,474
Capital Expenditures - Continuing Operations	**105,425**	132,913	161,259	160,084	163,582
Total Assets	**2,052,517**	2,004,278	1,912,385	1,818,683	1,738,116
Long-Term Debt	**590,002**	490,380	505,341	443,846	495,906
Basic Earnings Per Share - Continuing Operations *(1)*	**2.08**	1.84	1.62	1.56	1.56
Basic Earnings Per Share - Total *(1)*	**2.08**	1.84	1.62	1.58	1.58
Diluted Earnings Per Share - Continuing Operations *(1)*	**2.06**	1.82	1.61	1.56	1.55
Diluted Earnings Per Share - Total *(1)*	**2.06**	1.82	1.61	1.58	1.57
Return on Average Common Equity *(2)*	**11.5%**	10.6%	9.8%	10.1%	10.4%
Dividends Per Common Share	**1.34**	1.28	1.25	1.23	1.21
Dividend Payout Ratio	**65%**	70%	78%	78%	77%
Common Shares Outstanding - Year End	**39,665**	39,557	39,348	37,857	37,218
Number of Common Shareholders *(3)*	**12,661**	13,053	13,805	14,062	14,134

(1) Based on average number of shares outstanding.

(2) Earnings available for common shares divided by the 13-month average of month-end common equity balances.

(3) Holders of record at year end.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

Otter Tail Corporation and its subsidiaries form a diverse group of businesses with operations classified into three segments: Electric, Manufacturing and Plastics. Our primary financial goals are to maximize earnings and cash flows and to allocate capital profitably toward growth opportunities that will increase shareholder value. Meeting these objectives enables us to preserve and enhance our financial capability by maintaining desired capitalization ratios and a strong interest coverage position and preserving investment grade credit ratings on outstanding securities, which, in the form of lower interest rates, benefits both our customers and shareholders.

Our strategy is to continue to grow our largest business, the regulated electric utility, which will lower our overall risk, create a more predictable earnings stream, improve our credit quality and preserve our ability to fund the dividend. Over time, we expect the electric utility business will provide approximately 75% to 85% of our overall earnings. We expect our manufacturing and plastic pipe businesses will provide 15% to 25% of our earnings and will continue to be a fundamental part of our strategy. The actual mix of earnings in 2018, 2017 and 2016 was 66%, 68% and 80%, respectively, from our electric utility business and 34%, 32% and 20%, respectively, from our manufacturing and plastic pipe businesses, including unallocated corporate costs.

We expect that reliable utility performance along with rate base investment opportunities over the next five years will provide us with a strong base of revenues, earnings and cash flows. We also look to our manufacturing and plastic pipe companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. We expect much of our growth in these businesses in the next few years will come from utilizing expanded plant capacity from capital investments made in previous years. We will also evaluate opportunities to allocate capital to potential acquisitions in our Manufacturing and Plastics segments. We are a committed long-term owner and therefore we do not acquire companies in pursuit of short-term gains. However, we will divest operating companies that no longer fit into our strategy and risk profile over the long term.

Major growth strategies and initiatives in our future include:

- Planned capital budget expenditures of approximately $1.1 billion for the years 2019 through 2023, of which $973 million are for capital projects at Otter Tail Power Company (OTP), including:
  - $348 million for renewable wind and solar energy generation and conservation, including the Merricourt Wind Project scheduled for completion in 2020, the exercise of a purchase option on the Ashtabula III wind farm in 2022, a major investment in solar generation in 2022 and routine wind-power replacement projects.
  - $150 million for the Astoria natural gas-fired generation plant to replace Hoot Lake Plant capacity.
  - $145 million for numerous potential technology and infrastructure projects to transform future operations, including automated metering, telecommunications, geographic information systems, work and asset management systems, financial information systems, system infrastructure reliability improvements, outage management systems, and storage projects.
  - $122 million for transmission assets including new construction and routine replacement projects. New construction includes $7.8 million for the completion of the Big Stone South–Ellendale line in 2019.
- Continued investigation and evaluation of organic growth opportunities and evaluation of opportunities to allocate capital to potential acquisitions in our Manufacturing and Plastics segments.

In 2018:

- Our Electric segment net income increased 10.1% to $54.4 million from $49.4 million in 2017.
- Our Manufacturing segment net income increased 16.2% to $12.8 million from $11.1 million in 2017.

Our Plastics segment net income increased 9.8% to $23.8 million from $21.7 million in 2017.

Our net cash from continuing operations was $143.4 million.

Capital expenditures at OTP totaled $87.3 million as work continued toward completion on the Big Stone South–Ellendale Multi-Value Transmission Project (MVP).

OTP issued $100 million aggregate principal amount of its 4.07% Series 2018A Senior Unsecured Notes due February 7, 2048, using the proceeds to repay outstanding borrowings under the OTP Credit Agreement.

We decreased short-term borrowing by $93.8 million.

We paid out $53.2 million in common dividends in 2018.

The following table summarizes our consolidated results of operations for the years ended December 31:

(in thousands)	2018	2017
Operating Revenues:		
Electric	$450,198	$434,506
Manufacturing	268,409	229,712
Plastics	197,840	185,132
Total Operating Revenues	$916,447	$849,350
Net Income (Loss):		
Electric	$54,431	$49,446
Manufacturing	12,839	11,050
Plastics	23,819	21,696
Corporate	(8,744)	(9,753)
Total Net Income	$82,345	$72,439

Revenues in each of our business segments increased in 2018 compared with 2017, driven by higher sales volume for the Electric and Manufacturing segments and higher margins for the Plastics segment.

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Manufacturing segment revenues increased $38.7 million (16.8%). Revenues at BTD Manufacturing, Inc. (BTD) increased $36.8 million, with revenue increases at all of BTD's locations as a result of increased product sales across all end market categories. Included in the product sales are increased steel costs which are passed through to customers. Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $1.9 million due to increased sales of horticultural products. Electric segment revenues increased $15.7 million (3.6%) mainly due to a $13.3 million (3.6%) increase in retail sales revenue resulting from a 3.4% increase in retail kilowatt-hour (kwh) sales. The increase in electric revenue also included a $2.6 million (49.5%) increase in wholesale energy sales from OTP's generating units. Plastics segment revenues increased $12.7 million (6.9%), mainly due to a 9.4% increase in polyvinyl chloride (PVC) pipe prices, partially offset by a 2.3% decrease in pounds of pipe sold. Higher sales volume in 2017 was mainly due to buying spurred by concerns of product shortages and production delays related to 2017 hurricanes in the Gulf of Mexico.

A $12.7 million decrease in income tax expense in 2018 is mainly due to the decrease in the United States federal corporate income tax rate from 35% in 2017 to 21% in 2018 under the 2017 Tax Cuts and Jobs Act (TCJA).

The $9.9 million increase in net income in 2018 compared with 2017 reflects the following:

A $5.0 million increase in Electric segment net income from increased consumption due to favorable weather in 2018, and increases in interim rates, net of estimated refunds, in our North and South Dakota rate cases, partially offset by higher operating and maintenance expenses.

A $1.8 million increase in Manufacturing segment net income, mainly due to increased sales across almost all customer groups. Manufacturing segment net income was also impacted by the effect of the change in tax law under the TCJA.

A $2.1 million increase in Plastics segment net income was mainly due to higher pipe PVC prices and increased margins on pipe sales in 2018. Plastics segment net income was also impacted favorably by the effect of the change in tax law under the TCJA.

Corporate after-tax cost decreased $1.0 million in 2018. Corporate costs in 2017 included $7.2 million in additional tax expense due to the effect of the change in tax law under the TCJA. This was partially offset in 2018 primarily by increased charitable contributions and employee benefit costs.

As a result of the tax rate reduction included in the TCJA, deferred tax assets and liabilities were reduced in value in 2017. The impact by segment on 2017 income tax expense is summarized below:

(in thousands) **Decrease/(Increase)**

Electric	$	(458	)
Manufacturing		2,637	
Plastics		3,263	
Corporate		(7,198	)
Total	$	(1,756	)

Following is a more detailed analysis of our operating results by business segment for the years ended December 31, 2018, 2017 and 2016, followed by a discussion of our financial position at the end of 2018 and our outlook for 2019.

Results of Operations

This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes. See note 2 to consolidated financial statements for a complete description of our lines of business, locations of operations and principal products and services.

Intersegment Eliminations—Amounts presented in the following segment tables for 2018, 2017 and 2016 operating revenues, cost of goods sold, and other nonelectric operating expenses 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)*	2018	2017	2016
Operating Revenues:			
Electric	$ 57	$ 31	$ 34
Product Sales	--	26	--
Cost of Products Sold	21	18	6
Other Nonelectric Expenses	36	39	28

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Electric

The following table summarizes the results of operations for our Electric segment for the years ended December 31:

(in thousands)	2018	% change	2017	% change	2016
Retail Sales Revenues from Contracts with Customers	$388,690	3	$376,902	1	$374,506
Changes in Accrued Revenues under Alternative Revenue Programs	(439)	78	(1,971)	(194)	2,104
Total Retail Sales Revenue	$388,251	4	$374,931	--	$376,610
Wholesale Revenues – Company Generation	7,735	50	5,173	13	4,584
Other Revenues	54,269	--	54,433	18	46,189
Total Operating Revenues	$450,255	4	$434,537	2	$427,383
Production Fuel	66,815	12	59,690	9	54,792
Purchased Power – System Use	68,355	5	64,807	3	63,226
Other Operation and Maintenance Expenses	155,534	6	146,914	--	147,274
Depreciation and Amortization	55,935	5	53,276	(1)	53,743
Property Taxes	15,585	4	15,053	6	14,266
Operating Income	$88,031	(7)	$94,797	1	$94,082
Electric kilowatt-hour (kwh) Sales *(in thousands)*					
Retail kwh Sales	4,976,960	3	4,814,984	1	4,750,421
Wholesale kwh Sales – Company Generation	271,841	34	203,397	7	190,288
Heating Degree Days	6,904	16	5,931	12	5,314
Cooling Degree Days	567	49	380	(16)	451

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

	2018	2017	2016
Heating Degree Days	111.0%	93.9%	84.1%
Cooling Degree Days	123.5%	82.1%	97.4%

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 2018, 2017 and 2016, and between years.

2018 vs	2018 vs	2017 vs	2017 vs	2016 vs

	Normal	2017	Normal	2016	Normal
Effect on Diluted Earnings Per Share	$ 0.07	$0.11	$ (0.04)	$0.03	$ (0.07)

2018 Compared with 2017

The $13.3 million increase in retail revenue includes:

A $7.6 million increase in revenue related to the recovery of increased fuel and purchased power costs. The increase in fuel and purchase power costs was driven by a 3.4% increase in kwhs sold, combined with an increase in higher-cost purchased power in the fourth quarter of 2018 to provide replacement power during a nine-week scheduled fall maintenance outage at Big Stone Plant. The revenue increase was also driven by a $1.9 million reduction in estimated unbilled fuel revenues recorded in the fourth quarter of 2017.

A $6.3 million increase related to increased consumption due to colder and warmer weather in 2018 compared with 2017, evidenced by a 16.4% increase in heating-degree days and 49.2% increase in cooling degree days between the years.

A $5.7 million increase, net of an estimated refund, related to an interim rate increase implemented in January 2018 in conjunction with OTP’s 2017 general rate increase request in North Dakota.

A $4.2 million increase in North Dakota and Minnesota Renewable Resource Adjustment (RRA) rider revenues related to the expiration of federal production tax credit (PTC) eligibility on one of OTP’s wind farms.

A $2.8 million increase in Minnesota Conservation Improvement Program (MNCIP) cost recovery revenues and incentives.

A $0.7 million increase related to an interim rate increase implemented in October 2018 in conjunction with OTP’s 2018 general rate increase request in South Dakota.

partially offset by:

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A $9.6 million reduction in revenues for the provision of refunds related to the recovery of federal income taxes in current retail electric rates in our state jurisdictions and under Federal Energy Regulatory Commission approved transmission tariffs that are in excess of lower federal income taxes under the TCJA.

A $2.5 million decrease in North Dakota Environmental Cost Recovery (ECR) rider revenues due to a reduction in the return on equity component of the North Dakota rider from 10.75% in 2017 to 9.77% in 2018, lower federal taxes being recovered through the riders and a lower investment balance for environmental upgrades due to depreciation.

A $1.9 million reduction in North Dakota and South Dakota Transmission Cost Recovery (TCR) rider revenues related to a reduction in transmission costs, including lower federal income taxes under the TCJA.

Wholesale electric revenues increased $2.6 million due to a 33.7% increase in wholesale kwh sales and an 11.9% increase in wholesale electric prices. Increased demand and higher wholesale prices provided greater opportunity for wholesale energy sales and economic dispatch of OTP’s generating units in 2018 compared with 2017.

Production fuel costs increased $7.1 million, due to a 26.9% increase in kwhs generated from OTP’s fuel-burning plants to provide electricity for the increases in retail and wholesale demand driven by colder weather in the first four months and the last three months of 2018 and warmer weather from May through September 2018 compared with the same periods in 2017.

The cost of purchased power to serve retail customers increased $3.5 million. The cost per kwhs purchased increased by 16.1% while kwhs purchased decreased 9.2%. Increased system demand lead to the increase in cost per kwh purchased. Increased generation from company-owned generating units driven by higher market prices for electricity contributed to the decrease in kwhs purchased between the years.

Electric operating and maintenance expenses increased $8.6 million due to:

A $2.9 million increase in Big Stone Plant contracted maintenance expenses related to its 2018 nine-week scheduled fall maintenance outage.

A $2.4 million increase in conservation program spending.

A $1.9 million increase in benefit and other labor-related costs.

A $1.0 million increase in donations due to increased community giving in 2018 and to an irrevocable commitment of $0.5 million to fund OTP’s charitable foundation established in 2018.

A $0.4 million increase in other operating and maintenance expense.

Depreciation expense increased $2.7 million mainly due to the Big Stone South-Brookings transmission line being placed in service in September 2017 and to increased investments in other transmission assets.

Property tax expense increased $0.5 million in 2018 related to increased investments in our electric plant in service.

2017 Compared with 2016

The $1.7 million decrease in retail electric revenue includes:

A $5.3 million increase in retail revenue related to the recovery of increased fuel and purchased power costs due to a 1.4% increase in kwhs sold and a 4.8% increase in fuel and purchased power costs per kwh.

A $4.2 million increase in Minnesota base rate revenue mainly due to the transfer of recovery of environmental and transmission costs and investments from riders to base rates.

A $2.0 million increase in revenues due to increased consumption related to colder weather in 2017 reflected in the 11.6% increase in heating degree days between the years.

A $1.0 million increase in North Dakota TCR rider revenues as a result of increased investment in transmission assets qualifying for revenue recovery through the TCR rider.

more than offset by:

A $7.1 million reduction in Minnesota ECR rider and TCR rider revenues due to the transfer of recovery of qualifying costs from rider recovery into base rates, and due to declining revenue requirements related to lower asset values due to accumulated depreciation. Additionally, a lower return on equity in the Midcontinent Independent System Operator, Inc. (MISO) transmission tariff related to complaints currently under judicial review resulted in lower TCR revenues in Minnesota.

A $3.7 million decrease in MNCIP incentive and cost recovery revenues related to a $2.5 million reduction in incentives earned due to lower incentive rates and a $1.2 million reduction in spending on MNCIP programs. In 2017

OTP began operating under a new MNCIP program that was authorized by the Minnesota Public Utilities Commission. This new program lowered the incentive payout by 50% in 2017. The $1.2 million reduction in spending was due to a delay in regulatory approval for the implementation of an LED streetlight project.

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A $1.9 million decrease in revenue due to a change in estimate that reduced unbilled revenues.

A $1.5 million decrease in North Dakota and South Dakota ECR rider revenues resulting from lower values on qualifying assets due to accumulated depreciation.

The $0.6 million increase in revenue from wholesale electric sales from company-owned generation was mostly offset by a $0.4 million increase in fuel costs for wholesale generation.

The $8.2 million increase in other electric revenues includes:

A $7.8 million increase in MISO transmission tariff revenues, mainly driven by increased investment in regional transmission lines and revenues earned from the use of those lines by other electric service providers.

A $0.4 million increase in other revenues, mainly steam sales at Big Stone Plant.

Production fuel costs increased $4.9 million due to a 4.0% increase in kwhs generated. This was due to increase generation from Coyote Station and Hoot Lake Plant because of Coyote Station's greater availability, increased demand due to colder weather in 2017 and higher market prices for electricity that resulted in increased dispatch of Hoot Lake Plant.

The cost of purchased power to serve retail customers increased $1.6 million despite a 3.4% decrease in kwhs purchased. This was a result of higher market prices for electricity driven by increased demand in 2017 due, in part, to colder weather in 2017 than in 2016.

Electric operating and maintenance expenses decreased $0.4 million due to:

A $1.2 million decrease in transmission expenditures to independent system operators in 2017.

A $1.2 million decrease in MNCIP expenditures due to a delay in regulatory approval of an LED streetlight project planned for 2017.

A $0.7 million net reduction in other operating expenses.

mostly offset by:

A $2.7 million increase in labor and benefit costs due to increased wages and higher medical benefit payments.

Depreciation and amortization expense decreased $0.5 million due to lower depreciation rates.

Property tax expense increased $0.8 million mainly due to transmission line additions in South Dakota related to the construction of the Big Stone South–Ellendale and Big Stone South–Brookings 345-kiloVolt (kV) transmission projects.

Manufacturing

The following table summarizes the results of operations for our Manufacturing segment for the years ended December 31:

(in thousands)	2018	% change	2017	% change	2016
Operating Revenues	$268,409	17	$229,738	4	$221,289
Cost of Products Sold	205,699	17	176,473	3	171,732
Other Operating Expenses	29,650	25	23,785	8	21,994
Depreciation and Amortization	14,794	(4)	15,379	(3)	15,794
Operating Income	$18,266	30	$14,101	20	$11,769

2018 Compared with 2017

The $38.7 million increase in revenues in our Manufacturing segment includes the following:

Revenues at BTD increased $36.8 million, including increases of $33.8 million in parts revenue, including increased sales of $9.4 million to manufacturers of agricultural equipment, $7.8 million to manufacturers of recreational vehicles, $7.5 million to manufacturers of construction equipment, $4.6 million to manufacturers of industrial equipment, and $3.1 million to manufacturers of lawn and garden equipment. Included in the parts revenue increases is the pass through of higher material costs of $12.7 million, with the remaining increase due to higher sales volume and a $1.5 million increase in pricing unrelated to material cost increases. Revenues from scrap metal sales increased $2.3 million due to higher scrap volume from increased production and an 11% increase in scrap metal pricing.

Revenues at T.O. Plastics increased $1.9 million due to a $3.1 million increase in sales of horticultural containers, partially offset by decreases in sales of industrial and life sciences products totaling $1.2 million.

The $29.2 million increase in cost of products sold in our Manufacturing segment includes the following:

Cost of products sold at BTD increased $27.8 million due to increased sales volume and the $12.7 million in higher material costs.

Cost of products sold at T.O. Plastics increased $1.4 million related to the increase in product sales and higher labor and freight costs.

The $5.9 million increase in operating expenses in our Manufacturing segment includes the following:

Operating expenses at BTD increased $5.3 million because of the following:

o A $2.2 million increase in short-term incentives.

o A $2.0 million increase in labor, benefit and recruiting expenses due to hiring more employees.

o A $1.1 million increase in other administrative and general expenses.

Operating expenses at T.O. Plastics increased $0.6 million, mainly due to increases in labor and benefit expenses due to hiring more employees.

The $0.6 million decrease in depreciation in our Manufacturing segment includes decreases of $0.4 million at BTD related to reductions in stored tooling amortization and $0.2 million at T.O. Plastics due to certain manufacturing equipment being fully depreciated in 2018.

2017 Compared with 2016

The $8.4 million increase in revenues in our Manufacturing segment in 2017 compared with 2016 relates to the following:

Revenues at BTD increased $5.9 million. This is due to a $3.3 million increase in product sales to manufacturers of recreational and lawn and garden equipment from BTD’s Minnesota and Georgia manufacturing facilities, partially offset by lower sales in the energy end-use market at the Illinois facility. Scrap revenues increased $2.6 million due to increased volume and higher scrap-metal prices.

Revenues at T.O. Plastics increased $2.5 million, including increases of $1.3 million from sales of life science products, $1.0 million from sales of horticultural products and $0.2 million from sales of industrial products.

The $4.7 million increase in cost of products sold in our Manufacturing segment includes the following:

Cost of products sold at BTD increased $2.3 million because of the increase in product sales.

Costs of products sold at T.O. Plastics increased $2.4 million due to the increase in sales.

The $1.8 million increase in Manufacturing segment operating expenses includes the following:

Operating expenses at BTD increased $1.9 million because of the following:

- A $0.7 million increase in labor and benefit costs because of an increase in employees in a growing business.
- A $0.4 million increase in contracted service expenditures for consulting, software and telecommunications in response to increased business needs.
- A $0.4 million increase in property taxes.
- A $0.4 million increase in insurance costs.

Operating expenses at T.O. Plastics decreased $0.1 million between the years.

The $0.4 million decrease in depreciation in our Manufacturing segment includes decreases of $0.3 million at T.O. Plastics due to certain assets reaching the ends of their depreciable lives in 2017. Depreciation expense at BTD decreased $0.1 million year over year.

Plastics

The following table summarizes the results of operations for our Plastics segment for the years ended December 31:

(in thousands)	2018	% change	2017	% change	2016
Operating Revenues	$197,840	7	$185,132	20	$154,901
Cost of Products Sold	148,881	6	140,107	13	123,496
Other Operating Expenses	12,323	7	11,564	23	9,402
Depreciation and Amortization	3,719	(3)	3,817	(1)	3,861
Operating Income	$32,917	11	$29,644	63	$18,142

2018 Compared with 2017

Plastics segment revenues increased $12.7 million due to a 9.4% increase in PVC pipe prices on a 2.3% decrease in pounds of pipe sold. Cost of products sold increased $8.8 million, despite the 2.3% decrease in sales volume, due to an 8.8% increase in the cost per pound of pipe sold. The increase in pipe prices in excess of the increase in cost per pound of pipe sold resulted in an 11.3% increase in gross margin per pound of PVC pipe sold. Plastics segment operating expenses increased by $0.8 million mainly due to an increase in property maintenance costs, sales commissions and other selling and administrative costs.

Hurricane Harvey had a significant impact on market conditions from September through December 2017. Pounds of PVC pipe sold was lower in the last four months of 2018 compared with the same period in 2017. This was due to increased sales and pricing resulting from 2017 hurricanes in the Gulf Coast region of the United States where the majority of U.S. resin production plants are located. Major resin suppliers shut down production facilities which impacted raw material availability. This created pipe-availability concerns among distributors and contractors, accelerating pipe demand and favorably impacting our diluted earnings by an estimated $0.09 per share in 2017.

2017 Compared with 2016

Plastics segment revenues increased $30.2 million as a result of a 7.2% increase in pounds of PVC pipe sold and an 11.5% increase in PVC pipe prices between the years. Reaction to the hurricanes in the Gulf Coast region of the United States resulted in an estimated $12.5 million increase in revenues. Year over year improvement in normal business operations provided for the remainder of the revenue increase, along with increased prices. The $16.6 million increase in Plastics segment costs of product sold was due to the increase in sales volume and a 5.9% increase in the cost per pound of PVC pipe sold. The $2.2 million increase in operating expenses is mostly due to employee incentive pay related to the pipe companies’ stronger financial results compared with 2016.

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower.

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)	2018	% change	2017	% change	2016
Other Operating Expenses	$9,607	55	$6,182	(15)	$7,315
Depreciation and Amortization	218	199	73	55	47

Corporate operating expenses increased $3.4 million in 2018 as compared to 2017 due to the following:

A $1.7 million increase in charitable contributions due to an irrevocable commitment to fund Otter Tail Corporation’s charitable foundation established in 2018.

A $1.7 million increase in employee benefit costs.

Corporate operating expenses decreased $1.1 million in 2017 as compared to 2016 mainly due to a $0.6 million increase in the level of corporate costs allocated to the corporation’s operating companies and a $0.5 million reduction in labor costs due to a reduction in the number of corporate employees.

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Consolidated Interest Charges

(in thousands)	2018	% change	2017	% change	2016
Interest Charges	$30,408	3	$29,604	(7)	$31,886

The $0.8 million increase in interest charges in 2018 compared with 2017 is related to OTP's February 2018 issuance of $100 million in privately placed 4.07% Senior Unsecured Notes due February 7, 2048 (2018 Notes). Interest expense of $3.6 million in 2018 on the 2018 Notes was mostly offset by:

A $1.4 million reduction in long-term debt interest expense related to the retirement of OTP's $33.0 million outstanding 5.95%, Series A Senior Unsecured Notes at maturity on August 20, 2017 and the August 2017 early retirement of the remaining $15 million balance on our $50 million term loan term due February 5, 2018.

A $0.9 million reduction in short-term debt interest mainly related to the paydown of OTP's short-term debt outstanding on February 7, 2018 with proceeds from the 2018 Notes.

A $0.5 million increase in capitalized interest in 2018.

The $2.3 million decrease in interest charges in 2017 compared with 2016 is related to lower cost debt resulting from the issuance of $80.0 million of our 3.55% Guaranteed Senior Notes and the retirement of our remaining $52.3 million outstanding 9.000% Notes in December 2016 and the retirement of OTP's $33.0 million outstanding 5.95%, Series A Senior Unsecured Notes at maturity on August 20, 2017. The average level of debt outstanding between the periods increased by approximately $13.0 million with lower cost short-term debt being issued to retire higher cost long-term debt and being used to fund a portion of OTP's 2017 capital expenditures.

Consolidated OTHER INCOME

(in thousands)	2018	% change	2017	% change	2016
Other Income	$3,461	31	$2,632	(9)	$2,905

Other income increased $0.8 million in 2018 compared with 2017 mainly because of a $1.2 million increase in OTP’s allowance for equity funds used during construction (AFUDC) partially offset by a $0.5 million decrease in cash surrender values from corporate-owned life insurance.

Other income decreased $0.3 million in 2017 compared with 2016, mainly because of the receipt of $0.7 million in nontaxable corporate-owned life insurance proceeds in 2016 while no similar proceeds were received in 2017, partially offset by an increase in the cash surrender value of the life insurance policies in 2017 that was $0.3 million more than the increase in the cash surrender value in 2016.

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Consolidated Income Taxes

Income tax expense was $14.6 million in 2018 compared with $27.3 million in 2017 and $20.2 million in 2016. Income tax expense decreased $12.7 million in 2018 compared with 2017, mainly due to the decrease in the federal corporate income tax rate from 35% in 2017 to 21% in 2018 under the TCJA. Income tax expense increased $7.0 million in 2017 compared with 2016 mainly because of a $17.2 million increase in income before income taxes.

The following table provides a reconciliation of income tax expense calculated at the federal statutory rate on income before income taxes reported on our consolidated statements of income:

	For the Year Ended December 31,		
(in thousands)	2018	2017	2016
Income Before Income Taxes	$96,933	$99,695	$82,540
Tax Computed at Company's Net Composite Federal and State Statutory Rate (21% for 2018, 35% for 2017 and 2016)	$20,356	$34,893	$28,889
Increases (Decreases) in Tax from:			
State Income Taxes Net of Federal Income Tax Expense	5,210	4,368	2,869
Differences Reversing in Excess of Federal Rates	(3,432)	551	77
Federal PTCs	(3,111)	(7,527)	(7,175)
Permanent Differences, R&D Tax Credits, Unitary Tax and Other Adjustments	(1,864)	(1,873)	(1,262)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(1,033)	(850)	(850)
Excess Tax Deduction – Stock Compensation Awards	(708)	(751)	--
AFUDC – Equity	(431)	(322)	(280)
Employee Stock Ownership Plan Dividend Deduction	(298)	(509)	(537)
Investment Tax Credit Amortization	(98)	(164)	(350)
Corporate-owned Life Insurance	(3)	(845)	(680)
Section 199 Domestic Production Activities Deduction	--	(1,471)	(482)
Effect of TCJA Tax Rate Reduction on Value of Net Deferred Tax Assets	--	1,756	--
Total Income Tax Expense	$14,588	$27,256	$20,219
Effective Income Tax Rate	15.0 %	27.3 %	24.5 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs decreased 53.0% in 2018 compared with 2017 due to the PTC eligibility period ending for one of OTP's wind farms. OTP's kwh generation from its wind turbines eligible for PTCs increased 4.4% in 2017 compared with 2016 due to improved availability of the turbines and more favorable wind and operating conditions in 2017. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Impact of Inflation

OTP operates under regulatory provisions that allow price changes in fuel and certain purchased power costs to be passed to most retail customers through automatic adjustments to its rate schedules under fuel clause adjustments. Other increases in the cost of electric service must be recovered through timely filings for electric rate increases with the appropriate regulatory agency.

Our Manufacturing and Plastics segments consist entirely of businesses whose revenues are not subject to regulation by ratemaking authorities. Increased operating costs are reflected in product or services pricing with any limitations on price increases determined by the marketplace. Raw material costs, labor costs, fuel and energy costs and interest rates are important components of costs for companies in these segments. Any or all of these components could be impacted by inflation or other pricing pressures, with a possible adverse effect on our profitability, especially where increases in these costs exceed price increases on finished products. In recent years, our operating companies have faced strong inflationary and other pricing pressures with respect to steel, fuel, resin, and health care costs, which have been partially mitigated by pricing adjustments.

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Liquidity

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

(in thousands)	Line Limit	In Use on December 31, 2018	Restricted due to Outstanding Letters of Credit	Available on December 31, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	$130,000	$ 9,215	$ --	$120,785	$130,000
OTP Credit Agreement	170,000	9,384	300	160,316	57,329
Total	$300,000	$ 18,599	$ 300	$281,101	$187,329

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 Securities and Exchange Commission (SEC) under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 3, 2021. On May 3, 2018, 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 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. On May 1, 2018 our Distribution Agreement with J.P. Morgan Securities, LLC (JPMS) for our At-the-Market Offering Program ended as required under the agreement. No shares were issued under this program in 2018.

Equity or debt financing will be required in the period 2019 through 2023 given plans to fund construction of new rate base investments to expand our Electric segment. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 7 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the board of directors. On February 5, 2019 our board of directors increased the quarterly dividend from $0.335 to $0.35 per common share.

2018 Cash Flows Compared with 2017 Cash Flows

Net cash provided by operating activities was $143.4 million in 2018 compared with net cash provided by operating activities of $173.6 million in 2017. Primary reasons for the $30.2 million decrease in net cash provided by operations between the periods were:

A $9.9 million increase in net income.

A $2.1 million increase in depreciation and amortization expense.

A $1.5 million decrease in cash used for working capital items.

more than offset by:

A $20.0 million increase in discretionary contributions to the corporation’s funded pension plan.

A $2.4 million decrease in noncurrent liabilities and deferred credits in 2018 compared with a $19.3 million increase in 2017. The change was primarily driven by an increase in the discount rates used to value pension and other postretirement benefit liabilities.

A $4.8 million reduction in the level of increases in deferred tax liabilities related to the lower federal income tax rate under the TCJA.

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Net cash used in investing activities was $107.4 million in 2018 compared with $132.6 million in 2017. The $25.2 million decrease in cash used for investing activities includes a $27.5 million decrease in capital expenditures, mainly due to a $31.2 million reduction in cash used for capital expenditures at OTP as the Big Stone South–Brookings 345 kiloVolt (kV) transmission line project, placed in service September 2017, was under construction during the first nine months of 2017. OTP capital work on the Big Stone South–Ellendale 345-kV transmission line project and on a major project to replace its customer information system was winding down toward the end of 2018. OTP implemented its new customer information system in February 2019. Cash used for capital expenditures at BTD increased $3.4 million between periods mainly due to the addition of manufacturing equipment to add capabilities and expand capacity at all of BTD’s manufacturing plants. Corporate capital expenditures increased $0.5 million between periods for leasehold improvements and office equipment purchased in 2018 in connection with an April 2018 office move. The decrease in cash used for capital expenditures was partially offset by a $2.1 million decrease in proceeds from the disposal of noncurrent assets reflecting $1.5 million in proceeds in 2017 from the sale of property by OTP with no similar transaction in 2018 and a $0.6 million reduction in proceeds from the sale of investments by our captive insurance company, Otter Tail Assurance Limited.

Net cash used in financing activities was $51.4 million in 2018 compared with $24.8 million in 2017. Financing activities in 2018 included proceeds from the issuance of $100 million of 2018 Notes, which were used to pay down a portion of borrowings then outstanding under the OTP Credit Agreement. Financing activities in 2018 also included the distribution of $53.2 million in common dividend payments. (See discussion below on cash used for financing activities in 2017.)

2017 Cash Flows Compared with 2016 Cash Flows

The $10.2 million increase in cash provided by operating activities between the years includes a $10.1 million increase in net income and a $10.0 million reduction in discretionary contributions to our pension plan. Changes in long-term assets and liabilities, including deferred taxes, totaling $17.4 million were more than offset by a $26.9 million increase in cash used for working capital items. The increase in cash used for working capital between the periods is primarily due to a $19.1 million increase in cash used for payables and other current liabilities between the years at OTP related to the timing of payments, as cash use decreased $10.3 million in 2016 compared to an increase of $8.8 million in cash used for payables and other current liabilities in 2017. Cash used for inventories increased $6.2 million between the years primarily due to increased levels of inventory in each of our business segments.

Net cash used in investing activities was $132.6 million in 2017 compared with $159.3 million in 2016. The $26.7 million decrease in cash used for investing activities includes a $28.3 million decrease in cash used for capital expenditures partially offset by $1.5 million in acquisition purchase price adjustments. The decrease in cash used for capital expenditures is mainly due to a $31.2 million reduction in cash used for capital expenditures at OTP as work concluded on the Big Stone South–Brookings 345 kV transmission line project which was energized in September 2017. Capital expenditures increased $2.8 million in our Manufacturing and Plastics segments.

Net cash used in financing activities was $24.8 million in 2017 compared with $4.1 million in 2016. Financing activities in 2017 included a $69.5 million increase in net short-term borrowings under OTP's credit agreement, of which $33.0 million was used to redeem OTP's 5.95% Senior Unsecured Series A Notes which matured on August 20, 2017. The additional short-term borrowings were used to fund a portion of OTP's 2017 capital expenditures. Operating cash flows from our Manufacturing and Plastic's segments were used to repay an additional $15.2 million in long-term debt related to those operations. Financing activities in 2017 also included $2.4 million from an increase in checks written in excess of cash and $4.3 million in net proceeds from the issuance of common stock under our automatic dividend reinvestment and share purchase plan, partially offset by $1.8 million in stock repurchases related to tax withholding requirements for stock incentive awards. See note 5 to the consolidated financial statements for further information on stock issuances and retirements in 2017. We paid common stock dividends of $50.6 million in 2017 compared with $48.2 million in 2016.

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Capital Requirements

Capital Expenditures

We have a capital expenditure program for expanding, upgrading and improving our plants and operating equipment. Typical uses of cash for capital expenditures are investments in electric generation facilities and environmental upgrades, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, and computer hardware and information systems. The capital expenditure program is subject to review and is revised in light of changes in demands for energy, technology, environmental laws, regulatory changes, business expansion opportunities, the costs of labor, materials and equipment and our consolidated financial condition.

Cash used for consolidated capital expenditures was $105.4 million in 2018, $132.9 million in 2017 and $161.3 million in 2016. Estimated capital expenditures for 2019 are $203 million. Total capital expenditures for the five-year period 2019 through 2023 are estimated to be approximately $1.1 billion, including:

$348 million for renewable wind and solar energy generation and conservation, including the Merricourt Wind Project scheduled for completion in 2020, the exercise of a purchase option on the Ashtabula III wind farm in 2022, a major investment in solar generation in 2022 and routine wind-power replacement projects.

$150 million for the Astoria natural gas-fired generation plant to replace Hoot Lake Plant capacity.

$145 million for numerous potential technology and infrastructure projects to transform future operations, including automated metering, telecommunications, geographic information systems, work and asset management systems, financial information systems, system infrastructure reliability improvements, outage management systems, and storage projects.

$122 million for transmission assets including new construction and routine replacement projects. New construction includes $7.8 million for the completion of the Big Stone South–Ellendale line in 2019.

The breakdown of 2016, 2017 and 2018 actual cash used for capital expenditures and 2019 through 2023 estimated capital expenditures by segment is as follows:

(in millions)	2016	2017	2018	2019	2020	2021	2022	2023	2019-2023
Electric	$150	$119	$87	$183	$393	$120	$177	$100	$ 973
Manufacturing	8	10	13	15	14	14	19	15	77

Plastics	3	4	4	5	4	3	4	4	20
Corporate	--	--	1	--	--	--	--	--	--
Total	$161	$133	$105	$203	$411	$137	$200	$119	$ 1,070

Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2018 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Coal Contracts	$619	$23	$46	$47	$503
Debt Obligations	592	--	140	30	422
Interest on Debt Obligations	398	28	58	42	270
Capacity and Energy Requirements	230	25	38	24	143
Postretirement Benefit Obligations	111	6	12	14	79
Other Purchase Obligations (including land easements)	80	44	27	1	8
Operating Lease Obligations	31	6	11	7	7
Total Contractual Cash Obligations	$2,061	$132	$332	$165	$1,432

Coal contract obligations are based on estimated coal consumption and costs for the delivery of coal to Coyote Station from Coyote Creek Mining Company under the lignite sales agreement that ends in 2040, except for $1.0 million in purchase obligations in 2019 at Big Stone Plant. Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan, as we are not currently required to make a contribution to that plan.

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CAPITAL RESOURCES

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. 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 and transmission investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

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. On May 1, 2018 our Distribution Agreement with JPMS for our At-the-Market Offering Program ended.

Short-Term Debt

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

(in thousands)	Line Limit	In Use on December 31, 2018	Restricted due to Outstanding Letters of Credit	Available on December 31, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	$130,000	$ 9,215	$ --	$120,785	$130,000
OTP Credit Agreement	170,000	9,384	300	160,316	57,329
Total	$300,000	$ 18,599	$ 300	$281,101	$187,329

Under the Otter Tail Corporation Credit Agreement (OTC Credit Agreement) (as defined below), the maximum amount of debt outstanding in 2018 was $17.7 million on September 17, 2018 and the average daily balance of debt outstanding during 2018 was $5.5 million. The weighted average interest rate paid on debt outstanding under the OTC Credit Agreement during 2018 was 3.8% compared with 2.8% in 2017. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2018 was $122.0 million on January 16, 2018 and the average daily balance of debt outstanding during 2018 was $21.6 million. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2018 was 3.0% compared with 2.4% in 2017. The maximum amount of consolidated short-term debt outstanding in 2018 was $122.0 million on January 16, 2018 and the average daily balance of consolidated short-term debt outstanding during 2018 was $27.1 million. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2018 was 3.9%.

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.

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2016 Note Purchase Agreement

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

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2007 and 2011 Note Purchase Agreements

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

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

Financial Covenants

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

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

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

Under the 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 December 31, 2018, our Interest and Dividend Coverage Ratio calculated under the requirements of the OTC Credit Agreement and the 2016 Note Purchase Agreement was 4.35 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 December 31, 2018, OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.28 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 December 31, 2018, 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 December 31, 2018.

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OFf-Balance-Sheet Arrangements

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

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 $203 million compared with actual cash used for capital expenditures of $105 million in 2018. Our planned expenditures for 2019 include $61 million for the Merricourt Wind Project and $40 million for the planned natural gas-fired electric plant near Astoria, South Dakota.

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

	2018 EPS by Segment	2019 EPS Guidance Low	High
Electric	$ 1.36	$1.46	$1.49
Manufacturing	$ 0.32	$0.37	$0.41
Plastics	$ 0.60	$0.44	$0.48
Corporate	$ (0.22)	$(0.17)	$(0.13)
Total	$ 2.06	$2.10	$2.25
Return on Equity	11.5 %	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:

- Constructive outcome of a rate case filed in South Dakota in 2018. Interim rates went into effect on October 18, 2018. Our ability to obtain final rates similar to interim rates and reasonable rates of return depends on regulatory action under applicable statutes and regulations. We expect the effects of any reduction in interim or final rates as a result of lower tax rates in the TCJA to be offset by lower tax expenses. We cannot provide assurance our interim rates will become final.

- Increases in allowance for funds used during construction (AFUDC) for planned capital projects, including the Merricourt Wind Project, and increases in AFUDC and North Dakota Generation Cost Recovery Rider revenue relating to Astoria Station which is expected to begin construction in 2019.

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

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

partially offset by:

- Normal weather for 2019. Weather favorably impacted 2018 earnings per share by $.07 compared to normal.

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

We expect 2019 net income from our Manufacturing segment to increase over 2018 based on:

- 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 BTD's existing customer base. Scrap revenues are expected to increase as well based on increased volume with scrap prices staying flat between the years.

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

- Backlog for the manufacturing companies of approximately $211 million for 2019 compared with $166 million one year ago.

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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 expected increasing resin prices on slightly higher sales volumes in 2019 compared to 2018.

Corporate costs, net of tax, are expected to be lower in 2019 than in 2018.

The following table shows our 2018 capital expenditures and 2019 through 2023 anticipated capital expenditures and electric utility ending rate base:

(in millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Capital Expenditures:							
Electric Segment:							
Renewables and Natural Gas Generation		$103	$292	$18	$83	$2	$498
Transformative Technology and Infrastructure		3	25	39	46	32	145
Transmission (*includes replacements*)		37	38	13	11	23	122
Other		40	38	50	37	43	208
Total Electric Segment	$87	$183	$393	$120	$177	$100	$973
Manufacturing and Plastics Segments	18	20	18	17	23	19	97
Total Capital Expenditures	**$105**	**$203**	**$411**	**$137**	**$200**	**$119**	**$1,070**
Total Electric Utility Ending Rate Base	**$1,112**	**$1,210**	**$1,510**	**$1,539**	**$1,614**	**$1,631**	

The consolidated capital expenditure plan for the 2019-2023 time period calls for $1.1 billion based on the need for additional wind and solar in rate base, capital spending for the Astoria Station natural gas-fired plant that is part of our replacement solution for Hoot Lake Plant when it is retired in 2021, technology-related investments and transmission investments, including Self-Funded upgrades. Given the increased capital expenditure plan, our compounded annual growth rate in rate base is projected to be 7.9% over the 2018 to 2023 timeframe.

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.

Our outlook for 2019 is dependent on a variety of factors and is subject to the risks and uncertainties discussed in Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

Critical Accounting Policies Involving Significant Estimates

Our significant accounting policies are described in note 1 to consolidated financial statements. 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. The following critical accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements.

Pension and Other Postretirement Benefits Obligations and Costs

Pension and postretirement benefit liabilities and expenses for our electric utility and corporate employees are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. Further discussion of our pension and postretirement benefit plans and related assumptions is included in note 11 to consolidated financial statements.

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These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 30 or more years. These benefits can be paid out for up to 40 or more years after an employee retires. Estimates of liabilities and expenses related to these benefits are among our most critical accounting estimates. Although deferral and amortization of fluctuations in actuarially determined benefit obligations and expenses are provided for when actual results on a year-to-year basis deviate from long-range assumptions, compensation increases and healthcare cost increases or a reduction in the discount rate applied from one year to the next can significantly increase our benefit expenses in the year of the change. Also, a reduction in the expected rate of return on pension plan assets in our funded pension plan or realized rates of return on plan assets that are well below assumed rates of return or an increase in the anticipated life expectancy of plan participants could result in significant increases in recognized pension benefit expenses in the year of the change or for many years thereafter because actuarial losses can be amortized over the average remaining service lives of active employees.

The pension benefit cost for 2019 for our noncontributory funded pension plan is expected to be $3.4 million compared to $6.0 million in 2018, reflecting an increase in the estimated discount rate used to determine annual benefit cost accruals from 3.90% in 2018 to 4.50% in 2019. The assumed rate of return on pension plan assets will remain at 7.25% in 2019. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of “Aa” published by recognized rating agencies, along with bond matching models specific to our plan’s cash flows as a basis to determine the rate.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2018, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2018 pension benefit cost by $1,063,000; a 0.25 decrease in the discount rate would have increased our 2018 pension benefit cost by $1,120,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2018 pension benefit cost by $591,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2018 pension benefit cost by $576,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2018 pension benefit cost by $707,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase in the discount rate would have decreased our 2018 postretirement medical benefit costs by $244,000. A 0.25 decrease in the discount rate would have increased our 2018 postretirement medical benefit costs by $256,000. See note 11 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

We believe the estimates made for our pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are subject to change.

Taxation

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2018 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of Accounting Standards Codification (ASC) Topic 740, *Income Taxes*, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

Deferred income taxes are provided for revenue and expenses which are recognized in different periods for income tax and financial reporting purposes. We assess our deferred tax assets for recoverability taking into consideration our historical and anticipated earnings levels, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against our deferred tax assets. As facts and circumstances change, adjustments to the valuation allowance may be required.

Goodwill Impairment

Goodwill is required to be evaluated annually for impairment, according to ASC 350-20-35, *Goodwill – Subsequent Measurement*. We perform qualitative assessments of goodwill impairment and quantitative goodwill impairment testing annually in the fourth quarter. In addition, the quantitative testing is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which our reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

Under GAAP, we have the option of first performing a qualitative assessment to test goodwill for impairment on a reporting-unit basis. If, after applying the qualitative assessment, we conclude that it is *not* more likely than not that the fair value of the reporting unit is less than its carrying value, the quantitative goodwill impairment test is not required. If, after performing the qualitative assessment, we conclude that it is more likely than not that the fair value of the reporting unit is less than its carrying value, we would perform the quantitative goodwill impairment test.

The quantitative goodwill impairment test is a two-step process performed at the reporting unit level. We have determined the reporting units for our goodwill impairment test are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which our chief operating decision makers regularly review the operating results. For more information on our operating segments, see note 2 to consolidated financial statements. The first step of the quantitative impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. At December 31, 2018, the fair value substantially exceeded the carrying value at all our reporting units.

Conducting a qualitative assessment to determine if the fair value of a reporting unit is more likely than not in excess of its carrying value and determining the fair value of a reporting unit under quantitative testing requires judgment and the use of significant estimates which include assumptions about the reporting unit's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a combination of income and market approaches. We use a discounted cash flow methodology for our income approach. Under this approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. Under the market approach, we estimate fair value using multiples derived from comparable enterprise value to EBITDA multiples, comparable price earnings ratios, comparable enterprise value to sales multiples and if available, comparable sales transactions for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. When performing a qualitative assessment, we evaluate whether forecast scenarios used in the most recent quantitative fair value calculation continue to be reasonable considering industry events and the reporting unit's current circumstances. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not impairment is indicated.

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

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the Act). When used in this Form 10-K and in future filings by the Company with the SEC, in the Company's 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. Such statements are based on current expectations and assumptions and entail various risks and uncertainties that could cause actual results to differ materially from those expressed in such forward-looking statements. Such risks and uncertainties include the various factors set forth in Item 1A. Risk Factors of this Annual Report on Form 10-K and in our other SEC filings.

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Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2018 we had exposure to market risk associated with interest rates because OTP had $9.4 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under the OTP Credit Agreement and we had $9.2 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.50% under the Otter Tail Corporation Credit Agreement.

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

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

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

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

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Otter Tail Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota

February 22, 2019

We have served as the Company’s auditor since 1944.

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Otter Tail Corporation
Consolidated Balance Sheets, December 31

(in thousands)	**2018**	2017
Assets		
Current Assets		
Cash and Cash Equivalents	**$861**	$16,216
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $1,407 for 2018 and $1,094 for 2017)	**75,144**	68,466
Other	**9,741**	7,761
Inventories	**106,270**	88,034
Unbilled Receivables	**23,626**	22,427
Income Taxes Receivable	**2,439**	1,181
Regulatory Assets	**17,225**	22,551
Other	**6,114**	12,491
Total Current Assets	**241,420**	239,127
Investments	**8,961**	8,629
Other Assets	**35,759**	36,006
Goodwill	**37,572**	37,572
Other Intangibles–Net	**12,450**	13,765
Regulatory Assets	**135,257**	129,576
Plant		
Electric Plant in Service	**2,019,721**	1,981,018
Nonelectric Operations	**228,120**	216,937
Construction Work in Progress	**181,626**	141,067
Total Gross Plant	**2,429,467**	2,339,022
Less Accumulated Depreciation and Amortization	**848,369**	799,419
Net Plant	**1,581,098**	1,539,603
Total Assets	**$2,052,517**	$2,004,278

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Consolidated Balance Sheets, December 31

(in thousands, except share data)	**2018**	2017
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	**$18,599**	$112,371
Current Maturities of Long-Term Debt	**172**	186
Accounts Payable	**96,291**	84,677
Accrued Salaries and Wages	**24,857**	21,534
Accrued Taxes	**17,287**	16,808
Regulatory Liabilities	**738**	9,688
Other Accrued Liabilities	**12,149**	11,389
Total Current Liabilities	**170,093**	256,653
Pensions Benefit Liability	**98,358**	109,708
Other Postretirement Benefits Liability	**71,561**	69,774
Other Noncurrent Liabilities	**24,326**	22,769
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	**120,976**	100,501
Deferred Tax Credits	**19,974**	21,379
Regulatory Liabilities	**226,469**	232,893
Other	**1,895**	3,329
Total Deferred Credits	**369,314**	358,102
Capitalization (page 68)		
Long-Term Debt—Net	**590,002**	490,380
Cumulative Preferred Shares – Authorized 1,500,000 Shares Without Par Value; Outstanding – None	--	--
Cumulative Preference Shares – Authorized 1,000,000 Shares Without Par Value; Outstanding – None	--	--
Common Shares, Par Value $5 Per Share–Authorized, 50,000,000 Shares; Outstanding, 2018—39,664,884 Shares; 2017—39,557,491 Shares	**198,324**	197,787
Premium on Common Shares	**344,250**	343,450
Retained Earnings	**190,433**	161,286
Accumulated Other Comprehensive Loss	**(4,144)**	(5,631)
Total Common Equity	**728,863**	696,892
Total Capitalization	**1,318,865**	1,187,272
Total Liabilities and Equity	**$2,052,517**	$2,004,278

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Income–For the Years Ended December 31

(in thousands, except per-share amounts)	**2018**	2017	2016
Operating Revenues			
Electric			
Revenues from Contracts with Customers	**$450,637**	$436,477	$425,245
Changes in Accrued Revenues under Alternative Revenue Programs	**(439)**	(1,971)	2,104
Total Electric	**450,198**	434,506	427,349
Product Sales from Contracts with Customers	**466,249**	414,844	376,190
Total Operating Revenues	**916,447**	849,350	803,539
Operating Expenses			
Production Fuel – Electric	**66,815**	59,690	54,792
Purchased Power – Electric System Use	**68,355**	64,807	63,226
Electric Operation and Maintenance Expenses	**155,534**	146,914	147,274
Cost of Products Sold (depreciation included below)	**354,559**	316,562	295,222
Other Nonelectric Expenses	**51,544**	41,492	38,683
Depreciation and Amortization	**74,666**	72,545	73,445
Property Taxes – Electric	**15,585**	15,053	14,266
Total Operating Expenses	**787,058**	717,063	686,908
Operating Income	**129,389**	132,287	116,631
Interest Charges	**30,408**	29,604	31,886
Nonservice Cost Components of Postretirement Benefits	**5,509**	5,620	5,110
Other Income	**3,461**	2,632	2,905
Income Before Income Taxes	**96,933**	99,695	82,540
Income Tax Expense	**14,588**	27,256	20,219
Net Income	**$82,345**	$72,439	$62,321
Average Number of Common Shares Outstanding–Basic	**39,600**	39,457	38,546
Average Number of Common Shares Outstanding–Diluted	**39,892**	39,748	38,731
Basic Earnings Per Common Share	**$2.08**	$1.84	$1.62
Diluted Earnings Per Common Share	**$2.06**	$1.82	$1.61
Dividends Declared Per Common Share	**$1.34**	$1.28	$1.25

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Comprehensive Income–For the Years Ended December 31

(in thousands)	**2018**	2017	2016
Net Income	**$82,345**	$72,439	$62,321
Other Comprehensive Income (Loss):			
Unrealized Loss on Available-for-Sale Securities:			
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	**(105)**	(15)	(3)
(Losses) Gains Arising During Period	**(61)**	115	(14)
Income Tax Benefit (Expense)	**35**	(35)	6
Change in Unrealized Losses on Available-for-Sale Securities – net-of-tax	**(131)**	65	(11)
Pension and Postretirement Benefit Plans:			
Actuarial Gains (Losses) net of Regulatory Allocation Adjustment	**1,919**	(3,791)	(445)
Amortization of Unrecognized Postretirement Benefit Losses and Costs (note 11)	**985**	629	628
Income Tax (Expense) Benefit	**(755)**	1,266	(74)
Adjustment to Income Tax Expense Related to 2017 Tax Cuts and Jobs Act	**(531)**	--	--
Pension and Postretirement Benefit Plans – net-of-tax	**1,618**	(1,896)	109
Total Other Comprehensive Income (Loss)	**1,487**	(1,831)	98
Total Comprehensive Income	**$83,832**	$70,608	$62,419

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Common Shareholders' Equity

(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, December 31, 2015	**37,857,186**	**$189,286**	**$293,610**	**$126,025**	**$ (3,898) (a)**	**$605,023**
Common Stock Issuances, Net of Expenses	1,494,618	7,473	38,490			45,963
Common Stock Retirements and Forfeitures	(3,668)	(18)	(86)			(104)
Net Income				62,321		62,321
Other Comprehensive Income					98	98
Employee Stock Incentive Plan Expense			3,178			3,178
ASU 2016-09 Adoption			2,492	(623)		1,869
Common Dividends ($1.25 per share)				(48,244)		(48,244)
Balance, December 31, 2016	**39,348,136**	**$196,741**	**$337,684**	**$139,479**	**$ (3,800) (a)**	**$670,104**
Common Stock Issuances, Net of Expenses	257,059	1,285	3,684			4,969
Common Stock Retirements and Forfeitures	(47,704)	(239)	(1,560)			(1,799)
Net Income				72,439		72,439
Other Comprehensive Income					(1,831)	(1,831)
Employee Stock Incentive Plan Expense			3,642			3,642
Common Dividends ($1.28 per share)				(50,632)		(50,632)
Balance, December 31, 2017	**39,557,491**	**$197,787**	**$343,450**	**$161,286**	**$ (5,631) (a)**	**$696,892**
Common Stock Issuances, Net of Expenses	178,601	893	(986)			(93)
Common Stock Retirements and Forfeitures	(71,208)	(356)	(2,655)			(3,011)
Net Income				82,345		82,345
Other Comprehensive Income					1,487	1,487
Employee Stock Incentive Plan Expense			4,441			4,441
Common Dividends ($1.34 per share)				(53,198)		(53,198)
Balance, December 31, 2018	**39,664,884**	**$198,324**	**$344,250**	**$190,433**	**$ (4,144) (a)**	**$728,863**

(a) Accumulated Other Comprehensive Loss on December 31 is comprised of the following:

(in thousands)	**2018**	2017	2016

Unrealized (Loss) Gain on Marketable Equity Securities:			
Before Tax	**$(95)**	$71	$(29)
Tax Effect	**20**	(15)	10
Stranded Tax Effect	**(10)**	(10)	--
Unrealized (Loss) Gain on Marketable Equity Securities – net-of-tax	**(85)**	46	(19)
Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits:			
Before Tax	**(6,558)**	(9,462)	(6,300)
Tax Effect	**1,705**	2,991	2,519
Stranded Tax Effect	**794**	794	--
Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits – net-of-tax	**(4,059)**	(5,677)	(3,781)
Accumulated Other Comprehensive Loss:			
Before Tax	**(6,653)**	(9,391)	(6,329)
Tax Effect	**1,725**	2,976	2,529
Stranded Tax Effect	**784**	784	--
Net Accumulated Other Comprehensive Loss	**$(4,144)**	$(5,631)	$(3,800)

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Cash Flows—For the Years Ended December 31

(in thousands)	**2018**	2017	2016
Cash Flows from Operating Activities			
Net Income	**$82,345**	$72,439	$62,321
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	**74,666**	72,545	73,445
Deferred Tax Credits	**(1,405)**	(1,470)	(1,657)
Deferred Income Taxes	**19,224**	24,001	19,124
Change in Deferred Debits and Other Assets	**941**	(2,173)	(10,090)
Discretionary Contribution to Pension Plan	**(20,000)**	--	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	**(2,414)**	19,257	14,685
Allowance for Equity/Other Funds Used During Construction	**(2,194)**	(986)	(857)
Stock Compensation Expense – Equity Awards	**4,441**	3,642	3,178
Other—Net	**--**	10	7
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	**(8,559)**	(2,135)	(944)
Change in Inventories	**(18,236)**	(4,294)	1,874
Change in Other Current Assets	**(754)**	(3,060)	(2,541)
Change in Payables and Other Current Liabilities	**14,997**	(3,013)	11,502
Change in Interest Payable and Income Taxes Receivable/Payable	**396**	(1,186)	3,339
Net Cash Provided by Operating Activities	**143,448**	173,577	163,386
Cash Flows from Investing Activities			
Capital Expenditures	**(105,425)**	(132,913)	(161,259)
Proceeds from Disposal of Noncurrent Assets	**2,378**	4,491	4,837
Acquisition Purchase Price Cash Received	**--**	--	1,500
Cash Used for Investments and Other Assets	**(4,372)**	(4,168)	(4,402)
Net Cash Used in Investing Activities	**(107,419)**	(132,590)	(159,324)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**(345)**	2,434	(3,363)
Net Short-Term (Repayments) Borrowings	**(93,772)**	69,488	(37,789)
Proceeds from Issuance of Common Stock	**--**	4,349	44,435
Common Stock Issuance Expenses	**(108)**	**--**	(562)
Payments for Retirement of Capital Stock	**(3,011)**	(1,799)	(104)
Proceeds from Issuance of Long-Term Debt	**100,000**	--	130,000
Short-Term and Long-Term Debt Issuance Expenses	**(761)**	(380)	(888)
Payments for Retirement of Long-Term Debt	**(189)**	(48,231)	(87,547)
Dividends Paid and Other Distributions	**(53,198)**	(50,632)	(48,244)
Net Cash Used in Financing Activities	**(51,384)**	(24,771)	(4,062)
Net Change in Cash and Cash Equivalents	**(15,355)**	16,216	--
Cash and Cash Equivalents at Beginning of Period	**16,216**	--	--
Cash and Cash Equivalents at End of Period	**$861**	$16,216	$--

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Statements of Capitalization, December 31

(in thousands, except share data)	**2018**	2017
Short-Term Debt		
Otter Tail Corporation Credit Agreement	**$9,215**	$--
Otter Tail Power Company Credit Agreement	**9,384**	112,371
Total Short-Term Debt	**$18,599**	**$112,371**
Long-Term Debt		
Obligations of Otter Tail Corporation		
3.55% Guaranteed Senior Notes, due December 15, 2026	**$80,000**	$80,000
North Dakota Development Note, 3.95%, due April 1, 2018	**--**	27
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	**523**	684
Total – Otter Tail Corporation	**80,523**	80,711
Less: Current Maturities--net of Unamortized Debt Issuance Costs	**172**	186
Unamortized Long-Term Debt Issuance Costs	**407**	461
Total Otter Tail Corporation Long-Term Debt net of Unamortized Debt Issuance Costs	**79,944**	80,064
Obligations of Otter Tail Power Company		
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**	--
Total – Otter Tail Power Company	**512,000**	412,000
Less: Current Maturities--net of Unamortized Debt Issuance Costs	**--**	--
Unamortized Long-Term Debt Issuance Costs	**1,942**	1,684
Total Otter Tail Power Company Long-Term Debt net of Unamortized Debt Issuance Costs	**510,058**	410,316
Total Consolidated Long-Term Debt	**592,523**	492,711
Less: Current Maturities--net of Unamortized Debt Issuance Costs	**172**	186
Unamortized Long-Term Debt Issuance Costs	**2,349**	2,145
Total Consolidated Long-Term Debt net of Unamortized Debt Issuance Costs	**590,002**	490,380
Cumulative Preferred Shares—Without Par Value, Authorized 1,500,000 Shares; Outstanding: None		
Cumulative Preference Shares–Without Par Value, Authorized 1,000,000 Shares; Outstanding: None		
Total Common Shareholders' Equity	**728,863**	696,892
Total Capitalization	**$1,318,865**	$1,187,272

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Notes to Consolidated Financial Statements

For the years ended December 31, 2018, 2017 and 2016

1. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements of Otter Tail Corporation and its wholly owned subsidiaries (the Company) include the accounts of the following segments: Electric, Manufacturing and Plastics. See note 2 to consolidated financial statements for further descriptions of the Company's business segments. All intercompany balances and transactions have been eliminated in consolidation except profits on sales to the regulated electric utility company from nonregulated affiliates, which is in accordance with the requirements of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 980, *Regulated Operations* (ASC 980).

Prior Period Reclassifications

In 2018, the Company adopted Accounting Standards Update (ASU) 2014-09, *Revenues from Contracts with Customers (Topic 606)* (ASU 2014-09), and ASU 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). See additional information under Revenue Recognition and New Accounting Standards Adopted below. The adoption of the updated standards required the reclassifications of prior period revenues, expenses, operating income and other income and deductions to conform to presentation and classification requirements under the updated standards.

The updates in ASU 2014-09, which require the separate presentation of revenues from contracts with customers from other revenues on the face of the income statement, resulted in the separate presentation of adjustments to retail electric sales revenue under regulatory Alternative Revenue Programs (ARP's) from revenues from contracts with customers, but did not affect total operating or total electric operating revenues reported in prior years.

The updates in ASU 2017-07 require the reporting of the nonservice cost components of pension and other postretirement benefits outside of operating expense and operating income. The reclassification of these nonservice costs components has resulted in reductions in electric operation and maintenance expenses of $4,405,000 in 2017 and $3,951,000 in 2016, reductions in other nonelectric expenses of $1,215,000 in 2017 and $1,159,000 in 2016 and increases to operating income and the separate disclosure of nonservice cost components of postretirement benefits below the operating income line of $5,620,000 in 2017 and $5,110,000 in 2016.

Additionally, in 2018 the Company decided to no longer separate the residual effects of discontinued operations from the results of continuing operations due to the immaterial impact of discontinued operations relative to the results of continuing operations. The effects of discontinued operations are now included in other nonelectric expenses and income tax expense, with the liabilities of discontinued operations included in accounts payable and the cash flows from discontinued operations included in changes in accounts payable and other current liabilities in the Company’s consolidated financial statements for the years ended December 31, 2018, 2017 and 2016.

The above reclassifications resulted in no changes to the Company’s net income or retained earnings for the years ended December 31, 2017 and 2016.

Regulation and ASC 980

The Company’s regulated electric utility company, Otter Tail Power Company (OTP), accounts for the financial effects of regulation in accordance with ASC 980. This standard allows for the recording of a regulatory asset or liability for costs and revenues that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, OTP defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 4 to consolidated financial statements for further discussion.

OTP is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company’s nonelectric businesses.

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Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $1,206,000 in 2018, $741,000 in 2017 and $495,000 in 2016. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties (5 to 82 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.76% in 2018, 2.74% in 2017 and 2.88% in 2016. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at fair value if acquired in a business combination and are depreciated on a straight-line basis over the assets' estimated useful lives (2 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. No interest was capitalized on nonelectric plant in 2018, 2017 or 2016. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

Recoverability of Long-Lived Assets

The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying amount of the assets with net cash flows expected to be provided by operating activities of the business or related assets. If the sum of the expected future net cash flows is less than the carrying amount of the assets, the Company would recognize an impairment loss. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

Jointly Owned Facilities

OTP is a joint owner in two coal-fired steam-powered electric generation plants: Big Stone Plant near Big Stone City, South Dakota and Coyote Station near Beulah, North Dakota. OTP is also a joint owner, with other regional utilities, in four major in-service transmission lines and one additional major transmission line under construction. The following table provides OTP's ownership percentages and amounts included in the Company's December 31, 2018 and 2017 consolidated balance sheets for OTP's share of jointly owned assets in each of these jointly owned facilities:

Jointly Owned Facilities *(dollars in thousands)*	OTP	Electric Plant	Construction	Accumulated	Net Plant
	Ownership		Work in	Depreciation	

	Percentage	in Service	Progress		
December 31, 2018					
Big Stone Plant	53.9%	$336,051	$ 361	$ (92,007)	$244,405
Coyote Station	35.0%	177,713	2,588	(100,997)	79,304
Fargo–Monticello 345 kV line	14.2%	78,184	--	(5,891)	72,293
Brookings–Southeast Twin Cities 345 kV line	4.8%	26,281	--	(1,713)	24,568
Bemidji–Grand Rapids 230 kV line	14.8%	16,331	--	(2,091)	14,240
Big Stone South–Brookings 345 kV line	50.0%	53,235	(150)	(1,264)	51,821
Big Stone South–Ellendale 345 kV line[1]	50.0%	--	106,490	--	106,490
December 31, 2017					
Big Stone Plant	53.9%	$329,942	$ 1,074	$ (74,165)	$256,851
Coyote Station	35.0%	177,721	158	(103,944)	73,935
Fargo–Monticello 345 kV line	14.2%	78,192	--	(4,667)	73,525
Brookings–Southeast Twin Cities 345 kV line	4.8%	26,269	--	(1,293)	24,976
Bemidji–Grand Rapids 230 kV line	14.8%	16,331	--	(1,753)	14,578
Big Stone South–Brookings 345 kV line	50.0%	53,225	--	(434)	52,791
Big Stone South–Ellendale 345 kV line[1]	50.0%	--	89,980	--	89,980

[1]Midcontinent Independent System Operator, Inc. (MISO) Multi-Value Project (MVP) designation provides for a return on invested funds while under construction under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).

The Company’s share of direct revenue and expenses of the jointly owned facilities is included in operating revenue and expenses in the consolidated statements of income.

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

If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of December 31, 2018 could be as high as $53.9 million, OTP's 35% share of unrecovered costs.

Income Taxes

Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes investment tax credits over the estimated lives of related property. The Company records income taxes in accordance with ASC Topic 740, *Income Taxes,* and has recognized in its consolidated financial statements the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. The term "more-likely-than-not" means a likelihood of more than 50%. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 14 to consolidated financial statements regarding the Company's accounting for uncertain tax positions.

The Company also is required to assess the realizability of its deferred tax assets, taking into consideration the Company's forecast of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, valuation allowances against the Company's deferred tax assets. To the extent facts and circumstances change in the future, adjustments to the valuation allowance may be required.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law. The major impacts of the changes included in the TCJA are discussed in note 14 to consolidated financial statements.

Revenue Recognition

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

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

In addition to recognizing revenue from contracts with customers under ASC 606, the Company also records adjustments to Electric segment revenues for amounts subject to future collection under alternative revenue programs (ARPs) as defined in 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 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 FERC. These revenues account for over 80% of other electric revenues reported in the table of disaggregated revenues in note 2. 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 and RRA riders.
In South Dakota: TCR, ECR and Energy Efficiency Plan (conservation) riders.

OTP accrues ARP revenue on the basis of costs incurred, investments made and returns on those investments that qualify for recovery through established riders. Amounts billed under riders in effect at the time of the billing are included in revenues from contracts with customers 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 ARP revenue adjustments on a separate line in the revenue section of the Company’s consolidated statement of income. See table in note 3 for total revenues billed and accrued under ARP riders for the years ended December 31, 2018, 2017 and 2016.

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 and adjusts the revenue for volume rebate variable pricing considerations the company expects the customer will earn and for applicable early payment discounts the

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company expects the customer will take. For revenue recognized on products when shipped, the operating companies have no further obligation to provide services related to such 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. Billed amounts of revenue recognized are adjusted for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. For revenue recognized on shipped products, there is no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point. The Plastics segment has one customer for which it produces and stores a product made to the customer's specifications and design under a build and hold agreement. For sales to this customer, the operating company recognizes revenue as the custom-made product is produced, adjusting the amount of revenue for volume rebate variable pricing considerations the operating company expects the customer will earn and applicable early payment discounts the company expects the customer will take. Ownership of the pipe transfers to the customer prior to delivery and the operating company is paid a negotiated fee for storage of the pipe. Revenue for storage of the pipe is also recognized over time as the pipe is stored.

See operating revenue table in note 2 for a disaggregation of the Company's revenues by business segment for the years ended December 31, 2018, 2017 and 2016.

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.

Warranty Reserves

Certain products sold by the Company's manufacturing and plastics companies carry product warranties for one year after the shipment date. These companies' standard product warranty terms generally include post-sales support and repairs or replacement of a product at no additional charge for a specified period of time. While these companies engage in extensive product quality programs and processes, including actively monitoring and evaluating the quality of their component suppliers, they base their estimated warranty obligations on warranty terms, ongoing product failure rates, repair costs, product call rates, average cost per call, and current period product shipments. The Company's manufacturing and plastics companies have not incurred any significant warranty costs over the last three fiscal years.

Shipping and Handling Costs

The Company includes revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold.

Use of Estimates

The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

The Company considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

Investments

The following table provides a breakdown of the Company's investments at December 31:

(in thousands)	2018	2017
Cost Method:		
Economic Development Loan Pools	$34	$45
Other	123	115
Equity Method Partnerships	26	24
Marketable Debt Securities Classified as Available-for-Sale	7,484	7,160
Marketable Equity Securities Classified as Available-for-Sale	1,294	1,285
Total Investments	$8,961	$8,629

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their fair values on December 31, 2018. See further discussion below.

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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 hierarchal 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 December 31, 2018 and December 31, 2017:

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	

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

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

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

Inventories

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

(in thousands)	December 31, 2018	December 31, 2017
Finished Goods	$37,130	$ 26,605
Work in Process	20,393	14,222
Raw Material, Fuel and Supplies	48,747	47,207
Total Inventories	$106,270	$ 88,034

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Goodwill and Other Intangible Assets

The Company accounts for goodwill and other intangible assets in accordance with the requirements of ASC Topic 350, *Intangibles—Goodwill and Other,* measuring its goodwill for impairment annually in the fourth quarter, and more often when events indicate the assets may be impaired. The Company does qualitative assessments of its reporting units with recorded goodwill to determine if it is more likely than not that the fair value of the reporting unit exceeds its book value. The Company also does quantitative assessments of its reporting units with recorded goodwill to determine the fair value of the reporting unit.

The following tables summarize changes to goodwill by business segment during 2018 and 2017:

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

(in thousands)	Gross Balance December 31, 2016	Accumulated Impairments	Balance (net of impairments) December 31, 2016	Adjustments to Goodwill in 2017	Balance (net of impairments) December 31, 2017
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 December 31, 2018 and December 31, 2017:

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	
December 31, 2017 *(in thousands)*				
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 8,994	$ 13,497	24-212
Covenant not to Compete	590	459	131	8
Other	154	17	137	32
Total	$ 23,235	$ 9,470	$ 13,765	

The amortization expense for these intangible assets was:

(in thousands)	2018	2017	2016
Amortization Expense – Intangible Assets	$ 1,315	$ 1,347	$ 1,436

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

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Supplemental Disclosures of Cash Flow Information

	As of December 31,	
(in thousands)	2018	2017
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$13,757	$13,887

(in thousands)	2018	2017	2016
Cash Paid (Received) During the Year for:			
Interest (net of amount capitalized)	$28,109	$29,791	$31,269
Income Taxes	$6,109	$5,064	$(1,291)

New Accounting Standards Adopted

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

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

ASU 2017-07—In March 2017 the FASB issued ASU 2017-07 with the intent of improving the presentation of net periodic pension cost and net periodic postretirement benefit cost. ASC Topic 715, *Compensation—Retirement Benefits* (ASC 715), does not prescribe where the amount of net benefit cost should be presented in an employer's income statement and does not require entities to disclose by line item the amount of net benefit cost that is included in the income statement or capitalized in assets. The amendments in ASU 2017-07 require that an employer report the service cost component of periodic benefit costs in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period, which the Company has provided in the electric operation and maintenance and other nonelectric expense lines on its income statement. The other components of net benefit cost as defined in ASC 715 are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The Company has provided the amount of the nonservice cost components of net periodic postretirement benefit costs in a separate line below interest expense on the face of its consolidated income statement. The amendments in ASU 2017-07 also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of internally manufactured inventory or a self-constructed asset). The amendments in ASU 2017-07 are effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The Company adopted the amendments on January 1, 2018. The amendments have been applied retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the Company’s consolidated income statements and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit cost in assets.

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

The Company’s nonservice cost components of net periodic postretirement benefit costs that were capitalized to plant in service in 2017 that would have been recorded as regulatory assets if the amendments in ASU 2017-07 were applicable in 2017 were $0.8 million. The Company’s nonservice costs components of net periodic postretirement benefit costs included in operating expense in 2017 and 2016 are now reported on a separate line outside of operating income and above other income in the Company’s consolidated statements of income. Additional information on the allocation of postretirement benefit costs for the years ended December 31, 2018, 2017 and 2016 is provided in note 11 for the Company’s major benefit programs presented.

New Accounting Standards Pending Adoption

ASU 2016-02—In February 2016 the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company has developed a list of all current leases outstanding. The Company has determined areas where the amendments in ASU 2016-02 are applicable to its businesses, evaluated transition options and determined the practical expedients it will elect on implementation. The Company will apply the amendments in ASU 2016-02 to its consolidated financial statements in the first quarter of 2019. Other than first-time recognition of these types of operating leases on the Company's consolidated balance sheet, the implementation is not expected to have a significant impact on the Company's consolidated financial statements. See note 8 for further information on leases and the Company's elections for applying the new standard and the expected impacts on adoption.

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 will early adopt the amendments in ASU 2017-04 in 2019. In 2018, there was no indication that the carrying amount of any of the Company's reporting units exceeded the reporting unit's fair value. Therefore, there was no requirement to apply step 2 for impairment testing at December 31, 2018.

ASU 2018-02—In February 2018 the FASB issued ASU No. 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). The amendments in ASU 2018-02, which are narrow in scope, allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the 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 will adopt the amendments in ASU 2018-02 in the first quarter of 2019 and apply them in the period of adoption and not retrospectively. On adoption, the Company will reclassify $784,000 of income tax effects of the TCJA on the gross deferred tax amounts at the date of enactment of the TCJA from other comprehensive loss to retained earnings so the remaining gross deferred tax amounts related to items in other comprehensive loss will reflect current effective tax rates.

2. Business 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, and material handling components. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

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

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

No single customer accounted for over 10% of the Company's consolidated revenues in 2018, 2017 and 2016. While no single customer accounted for over 10% of 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 individually provided 22.1% and 17.0% 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 the Company's long-lived assets are within the United States and sales within the United States accounted for 98.4% of sales in 2018, 98.2% of sales in 2017 and 98.6% of sales in 2016.

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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 2018, 2017 and 2016 is presented in the following table:

(in thousands)	2018	2017	2016
Operating Revenue			
Electric Segment:			
Retail Sales Revenue from Contracts with Customers	$388,690	$376,902	$374,506
Changes in Accrued ARP Revenues	(439)	(1,971)	2,104
Total Retail Sales Revenue	388,251	374,931	376,610
Wholesale Revenues – Company Generation	7,735	5,173	4,584
Other Electric Revenues	54,269	54,433	46,189
Total Electric Segment Revenues	450,255	434,537	427,383
Manufacturing Segment:			
Metal Parts and Tooling	223,765	189,242	185,868
Plastic Products and Tooling	35,836	33,939	31,431
Other	8,808	6,557	3,990
Total Manufacturing Segment Revenues	268,409	229,738	221,289
Plastics Segment – Sale of PVC Pipe Products	197,840	185,132	154,901
Intersegment Eliminations	(57)	(57)	(34)
Total	$916,447	$849,350	$803,539
Cost of Products Sold			
Manufacturing	$205,699	$176,473	$171,732
Plastics	148,881	140,107	123,496
Intersegment Eliminations	(21)	(18)	(6)
Total	$354,559	$316,562	$295,222
Other Nonelectric Expenses			
Manufacturing	$29,650	$23,785	$21,994
Plastics	12,323	11,564	9,402
Corporate	9,607	6,182	7,315
Intersegment Eliminations	(36)	(39)	(28)
Total	$51,544	$41,492	$38,683
Depreciation and Amortization			
Electric	$55,935	$53,276	$53,743
Manufacturing	14,794	15,379	15,794
Plastics	3,719	3,817	3,861
Corporate	218	73	47
Total	$74,666	$72,545	$73,445
Operating Income (Loss)			
Electric	$88,031	$94,797	$94,082
Manufacturing	18,266	14,101	11,769
Plastics	32,917	29,644	18,142
Corporate	(9,825)	(6,255)	(7,362)
Total	$129,389	$132,287	$116,631
Interest Charges			
Electric	$26,365	$25,334	$25,069

Manufacturing	2,230	2,215	3,859
Plastics	609	633	1,034
Corporate and Intersegment Eliminations	1,204	1,422	1,924
Total	$30,408	$29,604	$31,886

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(in thousands)	2018	2017	2016
Income Tax Expense (Benefit)			
Electric	$5,685	$17,013	$16,366
Manufacturing	3,393	989	2,276
Plastics	8,728	7,448	6,538
Corporate	(3,218)	1,806	(4,961)
Total	$14,588	$27,256	$20,219
Net Income (Loss)			
Electric	$54,431	$49,446	$49,829
Manufacturing	12,839	11,050	5,694
Plastics	23,819	21,696	10,628
Corporate	(8,744)	(9,753)	(3,830)
Total	$82,345	$72,439	$62,321
Capital Expenditures			
Electric	$87,287	$118,444	$149,648
Manufacturing	13,316	9,916	8,429
Plastics	4,199	4,432	3,085
Corporate	623	121	97
Total	$105,425	$132,913	$161,259
Identifiable Assets			
Electric	$1,728,534	$1,690,224	$1,622,231
Manufacturing	187,556	167,023	166,525
Plastics	91,630	87,230	84,592
Corporate	44,797	59,801	39,037
Total	$2,052,517	$2,004,278	$1,912,385

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 2018, 2017 and 2016.

Major Capital Expenditure Projects

Merricourt Project—On November 16, 2016 OTP entered into an Asset Purchase Agreement (the Purchase Agreement) with EDF Renewable Development, Inc. and certain of its affiliated companies (EDF) to purchase and assume the development assets and certain specified liabilities associated with a 150-megawatt (MW) wind farm in southeastern North Dakota (the Merricourt Project) for a purchase price of approximately $34.7 million, subject to adjustments for interconnection costs. The Purchase Agreement will close on satisfaction of various closing conditions (including regulatory approvals). Also on November 16, 2016, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement with EDF pursuant to which EDF will develop, design, procure, construct, interconnect, test and commission the wind farm with a targeted completion date in 2020 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. Depending on the timing of MISO interconnection approval, construction of the Merricourt Project is currently anticipated to begin in mid-2019. The agreements contain customary representations, warranties, covenants and indemnities for this type of transaction. As of December 31, 2018, OTP had capitalized approximately $4.9 million in development costs associated with the Merricourt Project. A final order for an Advance Determination of Prudence (ADP), subject to qualifications and compliance obligations, and a Certificate of Public Convenience and Necessity were issued by the NDPSC on November 3, 2017. On October 26, 2017 the MPUC approved the facility under the Renewable Energy Standard making the Merricourt Project eligible for cost recovery under the Minnesota Renewable Resource Recovery rider, subject to qualifications and reporting obligations.

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Astoria Station—OTP is moving forward with plans for the development, construction and ownership of this 250-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. As of December 31, 2018, OTP had capitalized approximately $8.3 million in development and other costs associated with Astoria Station. On August 3, 2018 the SDPUC issued an order granting a site permit for Astoria Station. A final order granting ADP for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations. The interconnection agreement for Astoria Station was executed by MISO in December 2018 and accepted by the FERC in January 2019. In a September 26, 2018 hearing the NDPSC approved an overall annual revenue increase for OTP and established a Generation Cost Recovery rider for future recovery of costs incurred for Astoria Station.

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345 kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., and the parties will 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. Construction began on this line in the second quarter of 2016 and the line was energized on February 6, 2019. OTP's capitalized costs on this project as of December 31, 2018 were approximately $106 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings 345-kV MVP—OTP invested approximately $73 million, which includes assets that are 100% owned by OTP, and has a 50.0% ownership interest in the jointly-owned assets of this 70-mile transmission line energized in 2017.

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

Reagent Costs

OTP's systemwide costs for reagents are expected to increase to approximately $2.2 million annually through May 2021 when Hoot Lake Plant is expected to be retired. The Minnesota, North Dakota and South Dakota share of costs are approximately 50%, 40% and 10%, respectively. Reagent costs for the Big Stone Plant Air Quality Control System (AQCS) and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) were initially incurred in 2015 when projects went into service.

Minnesota

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

The MPUC’s order also included: (1) the determination that all costs (including FERC allocated costs and revenues) of the Big Stone South–Brookings and Big Stone South–Ellendale MVPs will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP’s Minnesota customers (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 will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

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

Minnesota Conservation Improvement Programs (MNCIP)—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements or make a contribution to the state's energy and conservation account in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The Minnesota Department of Commerce (MNDOC) may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are included as recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

On May 25, 2016 the MPUC adopted the MNDOC’s proposed changes to the MNCIP financial incentive. The model provides utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. The financial incentive is also limited to 40% of 2017 MNCIP spending, 35% of 2018 spending and 30% of 2019 spending. The new model reduces the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

Based on results from the 2016 MNCIP program year, OTP recognized MNCIP financial incentives of $5.1 million in 2016, which included a $0.1 million true-up of 2015 financial incentives earned. The 2016 program resulted in an approximate 18% increase in energy savings compared to 2015 program results. On March 31, 2017 OTP requested approval for recovery of its 2016 MNCIP program costs not included in base rates, $5.0 million in performance incentives and an update to the MNCIP surcharge from the MPUC. On September 15, 2017 the MPUC issued an order approving OTP’s request with an effective date of October 1, 2017.

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of $2.6 million in 2017. The 2017 program resulted in a decrease in energy savings compared to 2016 program results of approximately 10%. OTP requested approval for recovery of its 2017 MNCIP program costs not included in base rates on March 30, 2018. The request included a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC. On June 13, 2018 OTP increased its request for a financial incentive to $2.9 million. On October 4, 2018, the MPUC issued an order approving OTP’s request of $2.9 million subject to further review by the MPUC to ensure no previous decisions conflict with the decision, with $0.3 million subject to a possible subsequent refund.

Based on results from the 2018 MNCIP program year, OTP recognized $3.0 million out of a potential $3.15 million in financial incentives earned in 2018. OTP will request approval for recovery of its 2018 program costs not included in base rates, a $3.15 million financial incentive and an update to its MNCIP surcharge from the MPUC by April 1, 2019.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) authorizes the MPUC to approve a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or that are exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's most recently completed general rate case or such other rate of return the MPUC determines is in the public interest. Additionally, following approval of a rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

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 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. A decision by the Minnesota Supreme Court is expected in either second or third quarter 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. In both situations the rates are proposed to be effective June 1, 2019 if a decision is made in late first quarter or early second quarter 2019. If the decision is made later than second quarter of 2019, it is likely the MPUC will delay its decision on the TCR rider update. The amount credited to Minnesota customers through the TCR through December 31, 2018 and subject to recovery if the Minnesota Court of Appeals decision is upheld, is approximately $2.3 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 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.

Reagent Costs and Emission Allowances—These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the Fuel Clause Adjustment (FCA) rider or base rates. In its 2016 general rate case order issued May 1, 2017 the MPUC denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs and through the FCA rider. Instead, the test-year costs are being recovered in base rates and variability of those costs in excess of amounts included in base rates will only be recovered to the extent actual kwh sales exceed forecasted kwh sales used to establish base rates.

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 return on equity and changes in allocation factors in the general rate case. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.3%. 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 Generation Cost Recovery 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. OTP has accrued an interim rate refund of $3.0 million as of December 31, 2018, which includes $0.8 million in excess revenue collected for income taxes under interim rates in effect in January and February 2018.

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

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Renewable Resource Adjustment—OTP has a North Dakota 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 through the rider.

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. On February 5, 2019 SDPUC staff and OTP requested that the SDPUC issue a procedural schedule setting evidentiary hearings for March 26-28, 2019. The full effects of the TCJA on South Dakota revenue requirements will be addressed in the rate case and incorporated into final rates at the conclusion of that case. The second step in the request is an additional 1.7% increase to recover costs for the proposed Merricourt wind generation facility when the facility goes into service. On February 15, 2019 the Company reached a partial settlement with SDPUC staff which requires SDPUC approval.

OTP's previously approved general rate increase in South Dakota of approximately $643,000 or approximately 2.32% was granted by the SDPUC in an order issued in April 2011 and effective in June 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

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

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 MATS 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.

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

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Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2015 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				
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
2015 Incentive and Cost Recovery	A – July 19, 2016	October 1, 2016	$ 8,590	$0.00275/kwh
2014 Incentive and Cost Recovery	A – July 10, 2015	October 1, 2015	$ 8,689	$0.00287/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
2016 Annual Update	A – July 5, 2016	September 1, 2016	$ 4,736	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	$ 7,203	Various
2014 Annual Update	A – February 18, 2015	March 1, 2015	$ 8,388	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
2016 Annual Update			$ 11,884	6.927% of base

	A – July 5, 2016	September 1, 2016		
2015 Annual Update	A – March 9, 2016	October 1, 2015	$ 12,104	7.006% of base
Renewable Resource Adjustment				
2018 Annual Update	A – August 29, 2018	November 1, 2018	$ 5,886	$.00244/kwh
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$ 1,279	$.00049/kwh
North Dakota				
Renewable Resource Adjustment				
2019 Annual Update	R – December 31, 2018	April 1, 2019	$ (236)	-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
2016 Annual Update	A – March 15, 2017	April 1, 2017	$ 9,156	7.005% of base
2015 Annual Update	A – June 22, 2016	July 1, 2016	$ 9,262	7.573% of base
2014 Annual Update	A – March 25, 2015	April 1, 2015	$ 5,441	4.069% 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
2016 Annual Update	A – December 14, 2016	January 1, 2017	$ 6,916	Various
2015 Annual Update	A – December 16, 2015	January 1, 2016	$ 9,985	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	January 1, 2018	$ 8,537	6.629% of base

	20, 2017			
2017 Annual Update	A – July 12, 2017	August 1, 2017	$ 9,917	7.633% of base
2016 Annual Update	A – June 22, 2016	July 1, 2016	$ 10,359	7.904% of base
2015 Annual Update	A – June 17, 2015	July 1, 2015	$ 12,249	9.193% of base
South Dakota				
Transmission Cost Recovery				
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
2015 Annual Update	A – February 12, 2016	March 1, 2016	$ 1,895	Various
2014 Annual Update	A – February 13, 2015	March 1, 2015	$ 1,538	Various
Environmental Cost Recovery				
2018 Interim Rate Reset	A – 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
2016 Annual Update	A – October 26, 2016	November 1, 2016	$ 2,238	$0.00536/kwh
2015 Annual Update	A – October 15, 2015	November 1, 2015	$ 2,728	$0.00643/kwh

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Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the years ended December 31:

Rate Rider *(in thousands)*	2018	2017	2016
Minnesota			
Conservation Improvement Program Costs and Incentives[1]	$12,028	$9,225	$12,920
Renewable Resource Adjustment	3,067	(196)	--
Environmental Cost Recovery	(24)	8,148	12,443
Transmission Cost Recovery	(2,039)	2,973	5,795
North Dakota			
Renewable Resource Adjustment	8,529	7,620	7,800
Environmental Cost Recovery	7,318	9,782	11,089
Transmission Cost Recovery	7,016	8,729	7,694
South Dakota			
Environmental Cost Recovery	1,676	2,345	2,538
Transmission Cost Recovery	1,664	1,843	1,820
Conservation Improvement Program Costs and Incentives	628	598	468

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

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, all OTP's 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 change into future 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 released its final order related to the TCJA docket which directs 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. OTP expects the rate change and refund to occur in the second quarter of 2019, pending MPUC approval of OTP’s January 3, 2019 compliance filing.

As described above, OTP’s current general rate cases in North Dakota and South Dakota reflect the ongoing impact of the TCJA in interim rates. OTP has accrued refund liabilities for the time periods when revenues were collected under rates set to recover higher levels of federal income taxes than OTP incurs under the lower federal tax rates in the TCJA. As of December 31, 2018, accrued refund liabilities related to the tax rate reduction were $8.4 million in Minnesota, $0.8 million in North Dakota for amounts collected reflecting the higher tax rates under interim rates in effect in January and February 2018, $1.0 million in South Dakota billed prior to October 18, 2018, and $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.

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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, has resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from $2.7 million on December 31, 2016 to $1.6 million as of December 31, 2018.

In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the two ROE complaints involving MISO transmission owners discussed above. In April 2017 the 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 are due April 10, 2019.

OTP believes its estimated accrued MISO Tariff ROE refund liability of $1.6 million as of December 31, 2018 related to the second MISO tariff ROE complaint is appropriate.

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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:

	December 31, 2018			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]	$6,346	$ 118,433	$124,779	see below
Conservation Improvement Program Costs and Incentives[2]	5,995	3,285	9,280	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	7,169	7,169	asset lives
Deferred Income Taxes[1]	--	2,423	2,423	asset lives
Deferred Marked-to-Market Losses[1]	1,661	743	2,404	24
Big Stone II Unrecovered Project Costs – Minnesota[1]	681	947	1,628	28
Nonservice Costs Components of Postretirement Benefits Capitalized for Ratemaking Purposes and Subject to Deferred Recovery[1]	--	986	986	asset lives
Debt Reacquisition Premiums[1]	207	753	960	165
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	455	--	455	12
Minnesota Renewable Resource Recovery Rider Accrued Revenues[2]	452	--	452	12
Minnesota Transmission Cost Recovery Rider Accrued Revenues[2]	444	--	444	12
Big Stone II Unrecovered Project Costs – South Dakota[1]	100	342	442	53
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[1]	328	--	328	4
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	240	--	240	12
South Dakota Deferred Rate Case Expenses Subject to Recovery[1]	178	--	178	12
Minnesota SPP Transmission Cost Recovery Tracker[1]	--	176	176	see below
Minnesota Environmental Cost Recovery Rider Accrued Revenues[2]	121	--	121	12
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
South Dakota Environmental Cost Recovery Rider Accrued Refund	207	--	207	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	--	187	187	24
North Dakota Renewable Resource Recovery Rider Accrued Refund	177	--	177	12
South Dakota Transmission Cost Recovery Rider Accrued Refund	168	--	168	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	--	166	166	see below
Refundable Fuel Clause Adjustment Revenues	121	--	121	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	60	--	60	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.*

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(in thousands)	December 31, 2017 Current	Long-Term	Total	Remaining Recovery/ Refund Period (months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$9,090	$112,487	$121,577	see below
Conservation Improvement Program Costs and Incentives[2]	7,385	2,774	10,159	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,651	6,651	asset lives
Deferred Marked-to-Market Losses[1]	4,063	2,405	6,468	36
Big Stone II Unrecovered Project Costs – Minnesota[1]	650	1,636	2,286	40
Debt Reacquisition Premiums[1]	254	960	1,214	177
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	309	--	309	12
Big Stone II Unrecovered Project Costs – South Dakota[1]	100	442	542	65
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[1]	75	--	75	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[1]	--	1,985	1,985	24
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	152	--	152	12
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	267	--	267	4
North Dakota Renewable Resource Recovery Rider Accrued Revenues[2]	206	236	442	15
Total Regulatory Assets	$22,551	$129,576	$152,127	
Regulatory Liabilities:				
Deferred Income Taxes	$--	$149,052	$149,052	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	83,100	83,100	asset lives
South Dakota Environmental Cost Recovery Rider Accrued Refund	187	--	187	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	48	180	24
South Dakota Transmission Cost Recovery Rider Accrued Refund	151	--	151	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	208	--	208	4
Refundable Fuel Clause Adjustment Revenues	5,778	--	5,778	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	349	--	349	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,667	--	1,667	11
Minnesota Transmission Cost Recovery Rider Accrued Refund	802	609	1,411	22
Minnesota Renewable Resource Recovery Rider Accrued Refund	409	--	409	12
Other	5	84	89	192
Total Regulatory Liabilities	$9,688	$232,893	$242,581	
Net Regulatory Asset/(Liability) Position	$12,863	$(103,317)	$(90,454)	

[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.

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

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

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*.

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

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

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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.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 165 months.

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.

Minnesota Renewable Resource Recovery Rider Accrued Revenues relate to an increase in renewable revenue requirements resulting from the expiration of tax credits for certain wind turbines. The balance represents amounts subject to recovery from Minnesota customers that have not been billed to Minnesota customers as of December 31, 2018.

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 December 31, 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.

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.

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.

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.

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 December 31, 2018.

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 December 31, 2018.

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

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

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

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

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 December 31, 2018.

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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 December 31, 2018.

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

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

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

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that were refundable to Minnesota customers as of December 31, 2017.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that were refundable to Minnesota customers as of December 31, 2017.

The Minnesota Renewable Resource Recovery Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that were refundable to Minnesota customers as of December 31, 2017.

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 and Common Share Distribution Agreement

On May 3, 2018 the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which 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. The shelf registration statement replaced the Company's prior shelf registration statement. On May 1, 2018 the Company's Distribution Agreement with J.P. Morgan Securities, LLC (JPMS) for the Company's At-the-Market Offering Program ended as required under the agreement.

2018 Common Stock Activity

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

Common Shares Outstanding, December 31, 2017	39,557,491
Issuances:	
Executive Stock Performance Awards (2015 awards)	114,648
Executive Stock Performance Awards (2016 and 2017 awards)	18,600
Vesting of Restricted Stock Units	26,575
Restricted Stock Issued to Directors	18,200
Directors Deferred Compensation	578
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(71,208)
Common Shares Outstanding, December 31, 2018	39,664,884

2014 Stock Incentive Plan

The 2014 Stock Incentive Plan (2014 Incentive Plan), which was approved by the Company's shareholders in April 2014, provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 1,900,000 common shares were authorized for granting stock awards under the 2014 Incentive Plan, of which 1,121,330 were available for issuance as of December 31, 2018. The 2014 Incentive Plan terminates on December 13, 2023.

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allowed eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period through December 31, 2016. For purchase periods beginning after January 1, 2017, the purchase price is 100% of the market price at the end of each six-month purchase period. On April 16, 2012, the Company's shareholders approved an amendment to the Purchase Plan, increasing the number of shares available under the Purchase Plan from 900,000 common shares to 1,400,000 common shares and making certain other changes to the terms of the Purchase Plan. Of the 1,400,000 common shares authorized to be issued under the Purchase Plan, 366,867 were available for purchase as of December 31, 2018. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for purchases for the Purchase Plan, 7,757 common shares were purchased in the open market in 2018, 4,202 common shares were purchased in the open market and 5,284 common shares were issued in 2017 and 53,875 common shares were issued in 2016.

Dividend Reinvestment and Share Purchase Plan

On May 3, 2018, the Company filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 common shares under the Company's Automatic Dividend Reinvestment 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. In 2018, 116,822 common shares were purchased in the open market to provide shares for the Plan. Although shares are purchased on the open market, they must be sold under the registration statement due to the features of the plan, leaving 1,383,178 common shares available for purchase or issuance under the Plan as of December 31, 2018. The shelf registration statement replaced the Company's prior shelf registration statement, which provided for the issuance of up to 1,500,000 common shares under the Plan. Common shares purchased in the open market under the Plan pursuant to the Company's prior shelf registration statement totaled 53,853 in 2018 and 87,634 in 2017. New common shares issued under the Plan pursuant to the Company's prior shelf registration statement totaled 97,698 in 2017 and 278,811 in 2016.

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income with no adjustments in 2018, 2017 and 2016. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company's directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting basic shares outstanding for the items listed in the following reconciliation:

	2018	2017	2016
Weighted Average Common Shares Outstanding – Basic	39,599,944	39,457,261	38,546,459
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	212,043	210,784	118,644
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	59,980	56,952	45,712
Nonvested Restricted Shares	17,751	20,380	16,778
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	2,478	2,970	3,417
Total Dilutive Shares	292,252	291,086	184,551
Weighted Average Common Shares Outstanding – Diluted	39,892,196	39,748,347	38,731,010

The effect of dilutive shares on earnings per share for the years ended December 31, 2018, 2017 and 2016, resulted in no differences greater than $0.016 between basic and diluted earnings per share in any period.

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6. Share-Based Payments

Purchase Plan

Through December 31, 2016, the Purchase Plan allowed employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six-month investment period. Under ASC Topic 718, *Compensation—Stock Compensation* (ASC 718), the Company was required to record compensation expense related to the 15% discount. The 15% discount resulted in compensation expense of $173,000 in 2016. For purchase periods beginning after January 1, 2017, the purchase price is 100% of the market price at the end of each six-month purchase period.

Restricted Stock Granted to Directors

Under the 1999 Incentive Plan and the 2014 Incentive Plan, restricted shares of the Company's common stock were granted to members of the Company's board of directors as a form of compensation. All remaining restricted shares issued under the 1999 Incentive Plan vested on April 8, 2017. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 9, 2018, 18,200 shares of restricted stock were granted to the Company's nonemployee directors. The grant-date fair value of each share of restricted stock granted on April 9, 2018 was $43.40 per share, the average of the high and low market price on the date of grant. The restricted shares granted in 2018 vest 33.3% per year on April 8 of each year in the period 2019 through 2021 and 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 agreement.

Presented below is a summary of the status of directors' restricted stock awards for the years ended December 31:

Directors' Restricted Stock Awards	2018		2017		2016	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	46,800	$ 32.65	46,334	$ 29.71	38,217	$ 29.78
Granted	18,200	43.40	17,600	37.75	23,200	28.66
Vested	21,775	31.94	17,134	29.93	15,083	28.28
Forfeited	--		--		--	
Nonvested, End of Year	43,225	37.53	46,800	32.65	46,334	29.71
Compensation Expense Recognized		$ 661,000		$ 658,000		$ 491,000

Fair Value of Shares Vested in Year	$ 696,000	$ 513,000	$ 427,000

Restricted Stock Granted to Employees

Under the 1999 Incentive Plan and 2014 Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. All remaining restricted shares issued under the 1999 Incentive Plan vested on April 8, 2017. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. No shares of restricted stock have been granted to employees since 2014.

Presented below is a summary of the status of employees' restricted stock awards for the years ended December 31:

Employees' Restricted Stock Awards	2018		2017		2016	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	2,895	$ 29.41	7,180	$ 29.72	13,581	$ 28.56
Granted	--		--		--	
Vested	2,895	29.41	4,285	29.94	6,401	27.25
Forfeited	--		--		--	
Nonvested, End of Year	--	--	2,895	29.41	7,180	29.72
Compensation Expense Recognized		$ 16,000		$ 70,000		$ 96,000
Fair Value of Awards Vested		$ 85,000		$ 128,000		$ 174,000

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Restricted Stock Units Granted to Executive Officers

On February 5, 2018, 15,200 restricted stock units under the 2014 Incentive Plan were granted to the Company's executive officers. The grant-date fair value of each restricted stock unit was $41.325 per share, the average of the high and low market price on the date of grant. The restricted stock units granted to executive officers in 2018 vest 25% per year on February 6 of each year in the period 2019 through 2022 and 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 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.

Presented below is a summary of the status of restricted stock unit awards granted to executive officers for the years ended December 31:

Executives' Restricted Stock Unit Awards	2018		2017		2016	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	47,750	$ 32.71	41,825	$ 30.23	24,300	$ 31.682
Granted	15,200	41.325	15,900	37.65	22,000	28.915
Vested	17,650	32.462	9,975	30.16	4,475	31.69
Forfeited	--		--		--	
Nonvested, End of Year	45,300	35.70	47,750	32.71	41,825	30.23
Compensation Expense Recognized		$ 769,000		$ 576,000		$ 446,000
Fair Value of Awards Vested		$ 573,000		$ 301,000		$ 142,000

Restricted Stock Units Granted to Employees

In 2018 the following restricted stock unit awards under the 2014 Incentive Plan were granted to key employees of the Company who are not executive officers:

	Grant Date	Units Granted	Grant-Date Fair Value per Award
Restricted Stock Units Vesting 100% on April 8, 2022	April 9, 2018	12,945	$ 38.45
Restricted Stock Units Vesting 100% on April 8, 2022	June 20, 2018	1,000	$ 42.46

Restricted Stock Units Vesting 100% on April 8, 2022	September 25, 2018	835	$ 43.25

The grant-date fair value of each restricted stock unit was based on the average of the high and low market price of the Company's common stock on the date of grant, discounted for the value of the dividend exclusion over the four-year vesting period. Under the terms of the restricted stock unit award agreements, all outstanding (unvested) restricted stock units held by a retiring grantee vest immediately on normal retirement.

Presented below is a summary of the status of employees' restricted stock unit awards for the years ended December 31:

Employees' Restricted Stock Unit Awards	2018		2017		2016	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	46,440	$ 27.07	47,370	$ 25.19	46,600	$ 23.75
Granted	14,780	38.99	10,995	33.28	17,220	24.54
Vested	8,925	25.23	11,550	25.30	12,250	19.03
Forfeited	2,825	25.86	375	26.92	4,200	24.51
Nonvested, End of Year	49,470	31.03	46,440	27.07	47,370	25.19
Compensation Expense Recognized		$ 351,000		$ 331,000		$ 307,000
Fair Value of Awards Vested		$ 225,000		$ 292,000		$ 233,000

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Stock Performance Awards Granted to Executive Officers

Agreements for stock performance awards have been granted under the 2014 Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The awards also include a performance incentive based on the Company's average 3-year adjusted return on equity (ROE) relative to a targeted average 3-year adjusted ROE. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until common shares, if any, are issued at the end of the performance measurement period.

On February 5, 2018 performance share awards were granted to the Company's executive officers under the 2014 Incentive Plan for the 2018-2020 performance measurement period. Under the 2018 performance share awards the aggregate award for performance at target is 54,000 shares. For target performance the participants would earn an aggregate of 27,000 common shares for achieving the target set for the Company's 3-year average adjusted ROE. The participants would also earn an aggregate of 27,000 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the Edison Electric Institute Index over the performance measurement period of January 1, 2018 through December 31, 2020, with the beginning and ending share values based on the average closing price of a share of the Company's common stock for the 20 trading days immediately following January 1, 2018 and the average closing price for the 20 trading days immediately preceding January 1, 2021. Actual payment may range from zero to 150% of the target amount, or up to 81,000 common shares. There are no voting or dividend rights related to these awards until the shares, if any, are issued at the end of the performance measurement period. The amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to an officer who is party to an Executive Employment Agreement with the Company is to be made at target at the date of any such event. The vesting of these awards is accelerated and paid at target on the event of a change in control. 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.

The table below provides a summary of stock performance awards granted and amounts expensed related to the stock performance awards:

Performance Period	Maximum Shares Subject To Award	Target Shares	Expense Recognized in the Year Ended December 31,			Earned Shares
			2018	2017	2016	

2018-2020	81,000	54,000	$1,121,000			
2017-2019	89,250	59,500	729,000	$854,000		7,500
2016-2018	122,250	81,500	772,000	580,000	$798,000	113,298
2015-2017	126,450	84,300	23,000	573,000	535,000	114,648
2014-2016	159,450	106,300	--	--	332,000	121,491
Total			$2,645,000	$2,007,000	$1,665,000	356,937

Stock-based payment expense recognized in 2018, 2017 and 2016 for the 2018-2020, 2017-2019 and 2016-2018 performance awards reflects the accelerated recognition of expense for outstanding and unvested awards of executives who are eligible for retirement and whose awards vest on normal retirement, as defined in the performance award agreements, prior to the vesting dates of the awards.

The earned shares shown in the table above for the 2016-2018 and 2017-2019 performance periods include vested shares issued in 2018 to a participant who retired on December 31, 2017 and had reached age 62 prior to retirement.

The earned shares shown in the table above for the 2016-2018 performance period also include shares received in 2019 by participants in the plan based on the Company achieving a total shareholder return ranking of 1 out of 41 companies in the EEI Index and an average 3-year adjusted return on equity in excess of the targeted average 3-year adjusted return on equity of 10.00% resulting in a payout at 145.17% of target.

The earned shares shown in the table above for the 2015-2017 performance period include shares received in 2018 by participants in the plan based on the Company achieving a total shareholder return ranking of 2 out of 42 companies in the EEI Index and an average 3-year adjusted return on equity in excess of the targeted average 3-year adjusted return on equity of 10.00% resulting in a payout at 136.00% of target.

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The earned shares shown in the table above for the 2014-2016 performance period include shares received in 2017 by participants in the plan based on the Company achieving a total shareholder return ranking of 19 out of 43 companies in the EEI Index and a resulting payout at 114.29% of target. The earned shares also include shares for a portion of the award that vested on normal retirement of the Company's former CEO on July 1, 2015 that were issued in 2016 following the 180-day deferral period required under the Internal Revenue Code at a value of $26.35 per share or $848,000.

In connection with the resignation of an executive officer in May 2014, the following unvested stock performance awards were forfeited: 8,900 granted in 2014.

As of December 31, 2018, the total remaining unrecognized amount of compensation expense related to stock-based compensation for all of the Company's stock-based payment programs was approximately $4.3 million (before income taxes), which will be amortized over a weighted average period of 1.9 years.

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 December 31, 2018, 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 December 31, 2018, OTP’s equity-to-total-capitalization ratio including short-term debt was 53.2% and its net assets restricted from distribution totaled approximately $477 million. Total capitalization for OTP cannot currently exceed $1.2 billion.

8. Leases

The Company leases rail cars for transporting coal, warehouse and office space, land and certain office, manufacturing and material handling equipment, and currently has no assets held under capital leases.

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 construction work in progress 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. Lease payment expenses including payments for rail car leases totaled $6,273,000, $6,237,000 and $6,711,000 in 2018, 2017 and 2016, respectively.

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The amounts of the Company’s future operating leases obligations of December 31, 2018 are as follows:

	Operating Leases		
(in thousands)	OTP	Nonelectric	Total
2019	$1,099	$ 5,086	$6,185
2020	1,077	4,800	5,877
2021	1,047	3,971	5,018
2022	214	3,740	3,954
2023	196	3,385	3,581
Beyond 2023	448	6,295	6,743
Total	$4,081	$ 27,277	$31,358

In February 2016, the FASB issued ASU No. 2016-02. The new standard requires lessees to record assets and liabilities on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement.

The Company adopted the new standard on January 1, 2019 as required under GAAP. 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 historical lease classifications determined under the requirements of ASC Topic 840. The Company has also elected the practical expedient related to land easements, allowing for the continuation of historical current accounting treatment for land easements on existing agreements. In addition, the Company has elected the hindsight practical expedient to determine the reasonably certain lease term for existing leases.

On implementation of the new lease accounting standard, ASC Topic 842, *Leases* in January 2019, the majority of the Company’s leased assets will be capitalized as right-of-use operating assets. Certain leases that are short-term in nature—less than one year—will not be capitalized, as a policy election, and the associated rent payments will continue to be charged directly to rent expense. Payment for certain other leases with immaterial obligations in the aggregate relative to the obligations associated with capitalized right-of-use operating assets will also not be capitalized but will continue to be charged directly to rent expense on a straight-line basis.

Leases in place at the time of adoption will be capitalized on the basis of their remaining payment obligation balances, discounted to present value based on an explicit or implicit borrowing rate or on the Company’s incremental borrowing rate appropriate to the leased asset and lease terms. The remaining payments for operating lease right-of use assets will be charged to expense on a straight-line basis over the life of the lease beginning in January 2019.

The Company estimates adoption of the standard will result in recognition of net lease assets and lease liabilities of approximately $20 million on January 1, 2019. The Company believes adoption of the new standard will not have a material effect on its liquidity and the standard is not expected to have an impact on the Company's debt-covenant compliance under its current debt agreements.

Because the leases to be capitalized as right of use assets under ASC Topic 842 are operating leases and were operating leases under ASC Topic 840, the adoption of the new standard will have no material impact on the Company's consolidated statements of income or cash flows.

9. Commitments and Contingencies

Construction and Other Purchase Commitments

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. OTP's other nonlease commitments charged to rent expense totaled $252,000, $280,000 and $272,000 in 2018, 2017 and 2016, respectively. 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 2041. 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 entered into a coal purchase agreement with Peabody COALSALES, LLC effective May 14, 2018 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 the portion contracted to be purchased in 2019 under an existing agreement with Contura Coal Sales, LLC. OTP has an all-requirements agreement with

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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. Land easement payments charged to rent expense totaled $605,000, $593,000 and $582,000 in 2018, 2017 and 2016, respectively.

The amounts of the Company’s construction program and other commitments and commitments under capacity and energy agreements, coal purchase and coal delivery contracts and land easements as of December 31, 2018, are as follows:

(in thousands)	Construction Program and Other Commitments	Capacity and Energy Requirements	Coal Purchase Commitments	OTP Land Easement Payments
2019	$ 43,887	$ 24,925	$ 23,397	$ 617
2020	23,939	24,844	22,645	630
2021	1,681	12,988	22,935	642
2022	--	11,827	22,793	655
2023	--	11,827	23,955	668
Beyond 2023	--	143,099	503,492	7,612
Total	$ 69,507	$ 229,510	$ 619,217	$ 10,824

Contingencies

OTP had a $1.6 million refund liability on its balance sheet as of December 31, 2018 representing its best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on the likelihood of the FERC reducing the ROE component of the MISO Tariff and ordering MISO to refund amounts charged in excess of the lower rate. 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 impacting the Company’s consolidated financial statements are those related to environmental remediation, risks associated with warranty claims relating to divested businesses that could exceed the established reserve amounts and litigation matters. Should all of these known items, excluding the ROE refund liability already recognized, result in liabilities being incurred, the loss could be as high as $1.0 million.

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 ACE Rule determines that the best system of emission reduction for greenhouse gas emissions from coal-fired power plants is to improve the plants' heat rates, 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. If the ACE Rule goes into effect, states will have three years after the final rule to submit a state implementation plan.

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 December 31, 2018 will not be material.

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10. Short-Term and Long-Term Borrowings

Short-Term Debt

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

(in thousands)	Line Limit	In Use on December 31, 2018	Restricted due to Outstanding Letters of Credit	Available on December 31, 2018	Available on December 31, 2017
Otter Tail Corporation Credit Agreement	$130,000	$ 9,215	$ --	$120,785	$130,000
OTP Credit Agreement	170,000	9,384	300	160,316	57,329
Total	$300,000	$ 18,599	$ 300	$281,101	$187,329

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2018 was $17.7 million on September 17, 2018 and the average daily balance of debt outstanding during 2018 was $5.5 million. The weighted average interest rate paid on debt outstanding under the OTC Credit Agreement during 2018 was 3.8% compared with 2.8% in 2017. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2018 was $122.0 million on January 16, 2018 and the average daily balance of debt outstanding during 2018 was $21.6 million. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2018 was 3.0% compared with 2.4% in 2017. The maximum amount of consolidated short-term debt outstanding in 2018 was $122.0 million on January 16, 2018 and the average daily balance of consolidated short-term debt outstanding during 2018 was $27.1 million. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2018 was 3.9%.

On October 29, 2012 the Company 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. The Company can draw on this credit facility to refinance certain indebtedness and support its operations and the operations of its subsidiaries. Borrowings under the OTC Credit Agreement bear interest at LIBOR plus 1.50%, subject to adjustment based on the Company's senior unsecured credit ratings or the issuer rating if a rating is not provided for the senior unsecured credit. The Company is 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 the Company and the businesses of its wholly owned subsidiary, Varistar and its subsidiaries, including restrictions on the Company's and Varistar's 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 the Company's credit ratings. The Company's obligations under the OTC Credit Agreement are guaranteed by certain of the Company's subsidiaries. Outstanding letters of credit issued by the Company 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 Otter Tail Corporation 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 credit 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 Issuances and Retirements

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 the Company entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which the Company agreed to issue to the purchasers, in a private placement transaction, $80 million aggregate principal amount of its 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The 2026 Notes were issued on December 13, 2016. The Company’s obligations under the 2016 Note Purchase Agreement and the 2026 Notes are guaranteed by its 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 the Company’s 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 the Company’s term loan agreement.

The Company 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 the Company of all of the 2026 Notes on or after September 15, 2026 will be made without any make-whole amount. The Company is required to offer to prepay all 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 the Company and its Material Subsidiaries sell a "substantial part" of its 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, the Company is 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 the Material Subsidiaries that became effective on execution of the 2016 Note Purchase Agreement. These include restrictions on the Company's and the 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 the Company's and the 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 the Company's or the 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 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 (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 the $33 million 5.95%, Series A Senior Unsecured Notes, which had been issued under the 2007 Note Purchase Agreement and matured on August 20, 2017.

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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 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."

Shelf Registration

On May 3, 2018 the Company filed a shelf registration statement with the 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.

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

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

December 31, 2017 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$112,371	$ --	$ 112,371
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
North Dakota Development Note, 3.95%, due April 1, 2018		27	27
PACE Note, 2.54%, due March 18, 2021		684	684
Total	$412,000	$ 80,711	$ 492,711
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	186	186
Unamortized Long-Term Debt Issuance Costs	1,684	461	2,145
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$410,316	$ 80,064	$ 490,380
Total Short-Term and Long-Term Debt (with current maturities)	$522,687	$ 80,250	$ 602,937

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The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2018 for each of the next five years are:

(in thousands)	2019	2020	2021	2022	2023
Aggregate Amounts of Debt Maturities	$172	$185	$140,166	$30,000	$ --

Financial Covenants

The Company and OTP were in compliance with the financial covenants in these debt agreements as of December 31, 2018.

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

The Company's and OTP's borrowing agreements are subject to certain financial covenants. Specifically:

Under the Otter Tail Corporation Credit Agreement and the 2016 Note Purchase Agreement, the Company may not permit the ratio of its Interest-bearing 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 (each measured on a consolidated basis) as provided in the agreements.

Under the 2016 Note Purchase Agreement, the Company may not permit our Priority Indebtedness to exceed 10% of its 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.

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.

11. Pension Plan and Other Postretirement Benefits

Pension Plan

The Company's noncontributory funded pension plan covers substantially all corporate employees and OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2013, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the plan. The plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. The Company reserves the right to discontinue the plan, but no change or discontinuance may affect the pensions theretofore vested.

The pension plan has a trustee who is responsible for pension payments to retirees and a separate pension fund manager responsible for managing the plan's assets. An independent actuary assists the Company in performing the necessary actuarial valuations for the plan.

The plan assets consist of common stock and bonds of public companies, U.S. government securities, cash and cash equivalents and alternative investments. None of the plan assets are invested in common stock or debt securities of the Company.

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The following table lists components of net periodic pension benefit cost for the year ended December 31:

(in thousands)	2018	2017	2016
Service Cost–Benefit Earned During the Period	$6,459	$5,629	$5,518
Interest Cost on Projected Benefit Obligation	13,452	14,139	14,195
Expected Return on Assets	(21,199)	(19,229)	(19,454)
Amortization of Prior Service Cost:			
From Regulatory Asset	16	120	189
From Other Comprehensive Income[1]	--	3	5
Amortization of Net Actuarial Loss:			
From Regulatory Asset	7,135	5,090	5,153
From Other Comprehensive Income[1]	183	125	127
Net Periodic Pension Cost[2]	$6,046	$5,877	$5,733

[1]*Corporate cost included in nonservice cost components of postretirement benefits.*

[2]*Allocation of Costs:*	*2018*	*2017*	*2016*
Service Costs included in OTP Capital Expenditures	*$1,542*	*$1,094*	*$1,009*
Service costs included in electric operation and maintenance expenses	*4,756*	*4,400*	*4,377*
Service costs included in other nonelectric expenses	*161*	*135*	*132*
Nonservice costs capitalized	*(99)*	*48*	*39*
Nonservice costs included in nonservice cost components of postretirement benefits	*(314)*	*200*	*176*

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2018	2017	2016
Discount Rate	3.90 %	4.60%	4.76%
Long-Term Rate of Return on Plan Assets	7.50 %	7.50%	7.75%
Rate of Increase in Future Compensation Level	See below	3.00%	3.13%
Participants to Age 39	4.50 %		
Participants Age 40 to Age 49	3.50 %		
Participants Age 50 and Older	2.75 %		

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2018	2017
Regulatory Assets:		
Unrecognized Prior Service Cost	$5	$21
Unrecognized Actuarial Loss	104,891	99,360
Total Regulatory Assets	$104,896	$99,381
Accumulated Other Comprehensive Loss:		

Unrecognized Prior Service Cost	$9	$9
Unrecognized Actuarial Loss	137	439
Total Accumulated Other Comprehensive Loss	$146	$448
Noncurrent Liability	$58,659	$67,399

Funded status as of December 31:

(in thousands)	2018	2017
Accumulated Benefit Obligation	$(297,972)	$(316,095)
Projected Benefit Obligation	$(328,442)	$(352,718)
Fair Value of Plan Assets	269,783	285,319
Funded Status	$(58,659)	$(67,399)

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The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations over the two-year period ended December 31, 2018:

(in thousands)	2018	2017
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$285,319	$254,346
Actual Return on Plan Assets	(21,334)	44,181
Discretionary Company Contributions	20,000	--
Benefit Payments	(14,202)	(13,208)
Fair Value of Plan Assets at December 31	$269,783	$285,319
Estimated Asset Return	(7.3%)	17.8 %
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$352,718	$314,637
Service Cost	6,459	5,629
Interest Cost	13,452	14,139
Benefit Payments	(14,202)	(13,208)
Actuarial (Gain) Loss	(29,985)	31,521
Projected Benefit Obligation at December 31	$328,442	$352,718

Weighted average assumptions used to determine benefit obligations at December 31:

	2018	2017
Discount Rate	4.50%	3.90%
Rate of Increase in Future Compensation Level:		
Participants to Age 39	4.50%	4.50%
Participants Age 40 to Age 49	3.50%	3.50%
Participants Age 50 and Older	2.75%	2.75%

The assumed rate of return on pension fund assets used for the determination of 2019 net periodic pension cost is 7.25%. The assumed long-term rate of return on plan assets is based primarily on asset category studies using historical market return and volatility data with forward looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically. The Company reviews its rate of return on plan asset assumptions annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with the Company's pension plan investment advisors, as well as input from actuaries who work with the pension plan and benchmarking to peer companies with similar asset allocation strategies.

Market-related value of plan assets—The Company's expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The Company bases actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

Measurement Dates:	2018	2017
Net Periodic Pension Cost	January 1, 2018	January 1, 2017
End of Year Benefit Obligations	January 1, 2018 projected to December 31, 2018	January 1, 2017 projected to December 31, 2017
Market Value of Assets	December 31, 2018	December 31, 2017

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The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2019 are:

(in thousands)	2019
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$5
Amortization of Unrecognized Actuarial Loss	4,642
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	9
Amortization of Unrecognized Actuarial Loss	114
Total Estimated Amortization	$4,770

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

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

(in thousands)	2019	2020	2021	2022	2023	Years 2024-2028
	$15,086	$15,689	$16,356	$17,017	$17,709	$ 96,186

The following objectives guide the investment strategy of the Company’s pension plan (the Plan):

The assets of the Plan will be invested in accordance with all applicable laws in a manner consistent with fiduciary standards including Employee Retirement Income Security Act standards (if applicable). Specifically:

- o The safeguards and diversity that a prudent investor would adhere to must be present in the investment program.
- o All transactions undertaken on behalf of the Plan must be in the best interest of plan participants and their beneficiaries.

The primary objective of the Plan is to provide a source of retirement income for its participants and beneficiaries.
The near-term primary financial objective of the Plan is to improve the funded status of the Plan.
A secondary financial objective is to minimize pension funding and expense volatility where possible.

The asset allocation strategy developed by the Company’s Retirement Plans Administration Committee (the Committee) is based on the current needs of the Plan and the objectives listed above. An asset/liability review is conducted annually or as often as necessary to assess the impact of various asset allocations on funded status and other financial variables. The current needs of the Plan, the overall investment objectives above, the investment preferences and risk tolerance of the Committee and the desired degree of diversification suggest the need for an investment allocation including multiple asset classes.

The asset allocation in the table below contains guideline percentages, at market value, of the total Plan invested in various asset classes. The Permitted Range is a guide and will at times not reflect the actual asset allocation as this will be dictated by market conditions, the independent actions of the Committee and/or Investment Managers and required cash flows to and from the Plan. The Permitted Range anticipates this fluctuation and provides flexibility for the Investment Managers' portfolios to vary around the target without the need for immediate rebalancing. The Investment Manager will proactively monitor the asset allocation and will direct the purchases and sales to remain within the stated ranges.

The policy of the Plan is to invest assets in accordance with the allocations shown below:

Asset Class / PBO Funded Status	**Permitted Range** **< 85% PBO**	**>=85% PBO**	**>=90% PBO**	**>=95% PBO**	**>=100% PBO**
Equity	39% -59%	34%-54%	24%-44%	14%-34%	0% -20%
Investment Grade Fixed Income	22% -42%	30%-50%	40%-60%	53%-73%	70%-100%
Below Investment Grade Fixed Income*	0% -15%	0% -15%	0% -15%	0% -10%	0% -10%
Other**	5% -20%	5% -20%	5% -20%	0% -15%	0% -15%

** Includes (but not limited to) High Yield Bond Fund and Emerging Markets Debt funds.*

*** Other category may include cash, alternatives, and/or other investment strategies that may be classified other than equity or fixed income, such* *as the Dynamic Asset Allocation fund.*

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The Company’s pension plan asset allocations at December 31, 2018 and 2017, by asset category are as follows:

Asset Allocation	2018	2017
Large Capitalization Equity Securities	17.5 %	23.5 %
International Equity Securities	17.0 %	18.1 %
Small and Mid-Capitalization Equity Securities	6.7 %	8.7 %
SEI Dynamic Asset Allocation Fund	4.0 %	5.0 %
Emerging Markets Equity Fund	3.4 %	5.5 %
Equity Securities	48.6 %	60.8 %
Fixed-Income Securities and Cash	47.1 %	35.2 %
Other – SEI Energy Debt Collective Fund	4.3 %	4.0 %
	100.0%	100.0%

The following table presents the Company’s pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy and assets measured using the NAV practical expedient to fair valuation as of December 31:

(in thousands)	2018	2017
Assets in Level 1 of the Fair Value Hierarchy	$258,307	$273,999
SEI Energy Debt Collective Fund at NAV	11,476	11,320
Total Assets	$269,783	$285,319

Fair Value Measurements of Pension Fund Assets

ASC 715, *Compensation – Retirement Benefits,* requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35.

The following table presents, the Company’s pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy as of December 31:

(in thousands)	2018	2017
Large Capitalization Equity Securities Mutual Fund	$47,198	$66,946
International Equity Securities Mutual Funds	45,912	51,636
Small and Mid-Capitalization Equity Securities Mutual Fund	17,971	24,848
SEI Dynamic Asset Allocation Mutual Fund	10,929	14,371
Emerging Markets Equity Fund	9,197	15,824
Fixed Income Securities Mutual Funds	127,098	100,373
Cash Management – Money Market Fund	2	1
Total Assets	$258,307	$273,999

The investments held by the SEI Energy Debt Collective Fund on December 31, 2018 and 2017 consist mainly of below investment grade high yielding bonds and loans of U.S. energy companies which trade at a discount to fair value. Redemptions are allowed semi-annually with a 95-day notice period, subject to fund director consent and certain gate, holdback and suspension restrictions. Subscriptions are allowed monthly with a three-year lock up on subscriptions. The Company invested $10.0 million in the SEI Energy Debt Fund in July 2015. The fund’s assets are valued in accordance with valuations reported by the fund’s sub-advisor or the fund’s underlying investments or other independent third-party sources, although SEI in its discretion may use other valuation methods, subject to compliance with ERISA (as applicable). The fund’s assets are valued as of the close of business on the last business day of each calendar month and are available 30 days after the end of a calendar quarter. On an annual basis, as determined by the investment manager in its sole discretion, an independent valuation agent is retained to provide a valuation of the illiquid assets of the fund and of any other asset of the fund, as determined by the investment manager in its sole discretion. The Company reviews and verifies the reasonableness of the year-end valuations.

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

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The following table lists components of net periodic pension benefit cost for the year ended December 31:

(in thousands)	2018	2017	2016
Service Cost–Benefit Earned During the Period	$408	$290	$252
Interest Cost on Projected Benefit Obligation	1,589	1,686	1,667
Amortization of Prior Service Cost:			
From Regulatory Asset	20	16	16
From Other Comprehensive Income[1]	34	38	38
Amortization of Net Actuarial Loss:			
From Regulatory Asset	206	285	293
From Other Comprehensive Income[1]	722	440	446
Net Periodic Pension Cost[2]	$2,979	$2,755	$2,712

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

[2]Allocation of Costs:	*2018*	*2017*	*2016*
Service costs included in electric operation and maintenance expenses	*$99*	*$94*	*$87*
Service costs included in other nonelectric expenses	*309*	*196*	*165*
Nonservice costs included in nonservice cost components of postretirement benefits	*2,571*	*2,465*	*2,460*

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2018	2017	2016
Discount Rate	3.85%	4.60%	4.76%
Rate of Increase in Future Compensation Level	2.92%	3.00%	3.13%

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2018	2017
Regulatory Assets:		
Unrecognized Prior Service Cost	$20	$40
Unrecognized Actuarial Loss	1,768	3,229
Total Regulatory Assets	$1,788	$3,269
Projected Benefit Obligation Liability – Net Amount Recognized	$(39,699)	$(42,308)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	$64	$98
Unrecognized Actuarial Loss	6,455	9,024
Total Accumulated Other Comprehensive Loss	$6,519	$9,122

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2018 and a statement of the funded status as of December 31 of both years:

(in thousands)	2018	2017
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Employer Contributions	1,505	1,175
Benefit Payments	(1,505)	(1,175)
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$42,308	$37,335
Service Cost	408	290
Interest Cost	1,589	1,686
Benefit Payments	(1,505)	(1,175)
Plan Amendments	--	--
Actuarial (Gain) Loss	(3,101)	4,172
Projected Benefit Obligation at December 31	$39,699	$42,308

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Weighted average assumptions used to determine benefit obligations at December 31:

	2018	2017
Discount Rate	4.46%	3.85%
Rate of Increase in Future Compensation Level:	3.40%	2.92%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2019 are:

(in thousands)	2019
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$5
Amortization of Unrecognized Actuarial Loss	124
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	17
Amortization of Unrecognized Actuarial Loss	348
Total Estimated Amortization	$494

Cash flows—The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

						Years
(in thousands)	2019	2020	2021	2022	2023	2024-2028
	$1,468	$1,527	$1,618	$2,214	$2,635	$ 14,215

Other Postretirement Benefits

The Company provides a portion of health insurance benefits for retired OTP and corporate employees. The retiree health insurance benefits will be available for all corporate employees and OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2010, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the plan. To be eligible for retiree health insurance benefits the employee must be 55 years of age with a minimum of 10 years of service. There are no plan assets. The following table lists components of net periodic postretirement benefit cost for the year ended December 31:

(in thousands)	2018	2017	2016
Service Cost–Benefit Earned During the Period	$1,526	$1,425	$1,301

Interest Cost on Projected Benefit Obligation	2,583	2,712	2,503
Amortization of Prior Service Cost			
From Regulatory Asset	--	(4)	134
From Other Comprehensive Income[1]	--	4	3
Amortization of Net Actuarial Loss			
From Regulatory Asset	1,648	936	379
From Other Comprehensive Income[1]	42	19	9
Net Periodic Postretirement Benefit Cost[2]	$5,799	$5,092	$4,329
Effect of Medicare Part D Subsidy	$(470)	$(561)	$(923)

[1]Corporate cost included in nonservice cost components of postretirement benefits.

[2]Allocation of Cost:	*2018*	*2017*	*2016*
Service Costs included in OTP capital expenditures	*$364*	*$277*	*$238*
Service costs included in electric operation and maintenance expenses	*1,124*	*1,114*	*1,032*
Service costs included in other nonelectric expenses	*38*	*34*	*31*
Nonservice costs capitalized	*1,020*	*712*	*554*
Nonservice costs included in nonservice cost components of postretirement benefits	*3,253*	*2,955*	*2,474*

Weighted average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2018	2017	2016
Discount Rate	3.81 %	4.46 %	4.57 %

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The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2018	2017
Projected Benefit Obligation Liability – Net Amount Recognized	$(71,561)	$(69,774)
Unrecognized Net Actuarial Loss (Gain):		
Regulatory Asset	$18,094	$18,927
Accumulated Other Comprehensive Income:	(107)	(111)
Unrecognized Net Actuarial Loss	$17,987	$18,816

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2018:

(in thousands)	2018	2017
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Company Contributions	3,183	3,290
Benefit Payments (Net of Medicare Part D Subsidy)	(6,684)	(6,534)
Participant Premium Payments	3,501	3,244
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$69,774	$62,571
Service Cost (Net of Medicare Part D Subsidy)	1,526	1,425
Interest Cost (Net of Medicare Part D Subsidy)	2,583	2,712
Benefit Payments (Net of Medicare Part D Subsidy)	(6,684)	(6,534)
Participant Premium Payments	3,501	3,244
Actuarial Loss	861	6,356
Projected Benefit Obligation at December 31	$71,561	$69,774
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$(50,958)	$(49,156)
Expense	(5,799)	(5,092)
Net Company Contribution	3,183	3,290
Accrued Postretirement Cost at December 31	$(53,574)	$(50,958)

Weighted average assumptions used to determine benefit obligations at December 31:

	2018	2017
Discount Rate	4.44%	3.81%

Assumed healthcare cost-trend rates as of December 31:

	2018	2017
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	7.00 %	5.85 %
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.00 %	6.03 %
Rate to Which the Cost-Trend Rate is Assumed to Decline	4.50 %	4.50 %
Year the Rate Reaches the Ultimate Trend Rate	2038	2038

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2018 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 9,095	$ (7,586)
Effect on Total of Service and Interest Cost	$ 758	$ (600)
Effect on Expense	$ 1,953	$ (1,589)

Measurement Dates:	2018	2017
Net Periodic Postretirement Benefit Cost	January 1, 2018	January 1, 2017
End of Year Benefit Obligations	January 1, 2018 projected to December 31, 2018	January 1, 2017 projected to December 31, 2017

The estimated net amounts of unrecognized prior service cost to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2019 are:

(in thousands)	2019
Decrease in Regulatory Assets:	
Amortization of Unrecognized Actuarial Loss	$1,570
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Actuarial Loss	39
Total Estimated Amortization	$1,609

Cash flows—The Company expects to contribute $4.2 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2019. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $0.4 million in 2019. The following benefit payments, which reflect expected future service, as appropriate, net of expected Medicare Part D subsidy receipts and participant premium payments, are expected to be paid:

(in thousands)	2019	2020	2021	2022	2023	Years 2024-2028
	$4,247	$4,322	$4,483	$4,698	$4,781	$ 24,183

401K Plan

The Company sponsors a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans by the Company and its subsidiary companies totaled $4,532,000 for 2018, $4,211,000 for 2017 and $3,877,000 for 2016.

Employee Stock Ownership Plan

The Company has a stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $398,000 for 2018, $612,000 for 2017 and $647,000 for 2016.

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 December 31, 2018 and December 31, 2017 related to the Otter Tail Corporation Credit Agreement and the OTP Credit Agreement were subject to variable interest rates of LIBOR plus 1.50% and LIBOR plus 1.25%, respectively, which approximate market rates.

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

	December 31, 2018		December 31, 2017	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$861	$861	$16,216	$16,216
Short-Term Debt	(18,599)	(18,599)	(112,371)	(112,371)
Long-Term Debt including Current Maturities	(590,174)	(601,513)	(490,566)	(543,691)

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13. Property, Plant and Equipment

(in thousands)	December 31, 2018	December 31, 2017
Electric Plant in Service		
Production	$905,224	$897,732
Transmission	512,832	500,352
Distribution	502,261	482,867
General	99,404	100,067
Electric Plant in Service	2,019,721	1,981,018
Construction Work in Progress	170,090	132,556
Total Gross Electric Plant	2,189,811	2,113,574
Less Accumulated Depreciation and Amortization	699,642	662,431
Net Electric Plant	$1,490,169	$1,451,143
Nonelectric Operations Plant		
Equipment	$170,634	$160,263
Buildings and Leasehold Improvements	53,011	52,280
Land	4,475	4,394
Nonelectric Operations Plant	228,120	216,937
Construction Work in Progress	11,536	8,511
Total Gross Nonelectric Plant	239,656	225,448
Less Accumulated Depreciation and Amortization	148,727	136,988
Net Nonelectric Operations Plant	$90,929	$88,460
Net Plant	$1,581,098	$1,539,603

The estimated service lives for rate-regulated properties is 5 to 82 years. For nonelectric property the estimated useful lives are from 2 to 40 years.

(years)	Service Life Range Low	High
Electric Fixed Assets:		
Production Plant	9	82
Transmission Plant	42	70
Distribution Plant	5	68
General Plant	5	50
Nonelectric Fixed Assets:		
Equipment	2	12
Buildings and Leasehold Improvements	5	40

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14. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (21% in 2018, and 35% in 2017 and 2016) to net income before total income tax expense for the following reasons:

(in thousands)	2018	2017	2016
Tax Computed at Federal Statutory Rate	$20,356	$34,893	$28,889
Increases (Decreases) in Tax from:			
State Income Taxes Net of Federal Income Tax Expense	5,210	4,368	2,869
Differences Reversing in Excess of Federal Rates	(3,432)	551	77
Federal Production Tax Credits (PTCs)	(3,111)	(7,527)	(7,175)
Permanent Differences, R&D Tax Credits, Unitary Tax and Other Adjustments	(1,864)	(1,873)	(1,262)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(1,033)	(850)	(850)
Excess Tax deduction - Equity Method Stock Awards	(708)	(751)	--
Allowance for Funds Used During Construction – Equity	(431)	(322)	(280)
Employee Stock Ownership Plan Dividend Deduction	(298)	(509)	(537)
Investment Tax Credit Amortization	(98)	(164)	(350)
Corporate-owned Life Insurance	(3)	(845)	(680)
Section 199 Domestic Production Activities Deduction	--	(1,471)	(482)
Effect of TCJA Tax Rate Reduction on Value of Net Deferred Tax Assets	--	1,756	--
Income Tax Expense	$14,588	$27,256	$20,219
Overall Effective Federal, State and Foreign Income Tax Rate	15.0 %	27.3 %	24.5 %
Income Tax Expense Includes the Following:			
Current Federal Income Taxes	$4,960	$4,434	$989
Current State Income Taxes	1,395	1,128	1,208
Deferred Federal Income Taxes	8,065	25,648	23,774
Deferred State Income Taxes	4,410	4,587	2,623
Federal PTCs	(3,111)	(7,527)	(7,175)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(1,033)	(850)	(850)
Investment Tax Credit Amortization	(98)	(164)	(350)
Total	$14,588	$27,256	$20,219
Total Income Before Income Taxes	$96,933	$99,695	$82,540

The Company's deferred tax assets and liabilities were composed of the following on December 31:

(in thousands)	2018	2017
Deferred Tax Assets		
Benefit Liabilities	$33,967	$32,328
Regulatory Tax Liability	33,228	39,465
Retirement Benefits Liabilities	32,664	31,894

North Dakota Wind Tax Credits	32,570	32,962
Federal PTCs	32,101	40,614
Cost of Removal	21,787	21,800
Differences Related to Property	6,842	6,499
Net Operating Loss Carryforward	2,489	3,203
Vacation Accrual	1,919	1,844
Investment Tax Credits	449	515
Other	3,218	668
Valuation Allowance	(600)	--
Total Deferred Tax Assets	$200,634	$211,792
Deferred Tax Liabilities		
Differences Related to Property	$(261,396)	$(257,906)
Retirement Benefits Regulatory Asset	(32,664)	(31,894)
Excess Tax over Book Pension	(15,145)	(14,077)
North Dakota Wind Tax Credits	(4,386)	(4,112)
Impact of State Net Operating Losses on Federal Taxes	(523)	(673)
Other	(7,496)	(3,631)
Total Deferred Tax Liabilities	$(321,610)	$(312,293)
Deferred Income Taxes	$(120,976)	$(100,501)

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs decreased 53.0% in 2018 compared with 2017 due to the PTC eligibility period ending for one of OTP's wind farms. OTP's kwh generation from its wind turbines eligible for PTCs increased 4.4% in 2017 compared with 2016. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Schedule of expiration of tax credits and tax net operating losses available as of December 31, 2018:

(in thousands)	Amount	2022-2032	2033-2038	2039-2043
United States				
Federal Tax Credits	$34,586	$ --	$ 34,586	$ --
State Net Operating Losses	2,489	2,396	93	--
State Tax Credits	33,106	273	3,326	29,507

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

(in thousands)	2018	2017	2016
Balance on January 1	$684	$891	$468
Increases Related to Tax Positions for Prior Years	6	28	406
Decreases Related to Tax Positions for Prior Years	--	(172)	--
Increases Related to Tax Positions for Current Year	778	143	114
Uncertain Positions Resolved During Year	(186)	(206)	(97)
Balance on December 31	$1,282	$684	$891

The balance of unrecognized tax benefits as of December 31, 2018 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2018 is not expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in the Company's consolidated statement of income. There was no amount accrued for interest on tax uncertainties as of December 31, 2018.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2018, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2015 for federal and North Dakota income taxes and prior to 2014 for Minnesota state income taxes.

TCJA

In December 2017 the TCJA was enacted. The TCJA includes a number of changes to existing U.S. tax laws that impact the Company, most notably a reduction of the federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017.

The Company measures deferred tax assets and liabilities using enacted tax rates that will apply in the years in which the temporary differences are expected to be recovered or paid. Accordingly, the Company's deferred tax assets and liabilities were remeasured to reflect the reduction in the U.S. corporate income tax rate from 35% to 21% in 2017. The revaluation for OTP required the creation of a regulatory liability and an offsetting reduction in deferred tax liability. This regulatory liability will generally be amortized over the remaining life of the related assets. On a consolidated financial statement basis, the revaluation resulted in a one-time, non-cash, income tax expense of approximately $1.8 million in 2017. The impacts of the TCJA adjustments to deferred taxes and regulatory liabilities are provided in the reconciliation below:

(in thousands)	Deferred Tax Liability	Deferred Tax Regulatory Liability
Balance on January 1, 2017	$226,591	$ 818
Change due to 2017Accruals and Amortizations	20,012	376
TCJA Deferred Tax Valuation Adjustment	(109,072)	109,072
Tax Effect on TCJA Deferred Tax Valuation Adjustment	(38,786)	38,786
TCJA Adjustment to Income Tax Expense	1,756	--
Balance on December 31, 2017	$100,501	$ 149,052

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The Company recognized the income tax effects of the TCJA in its 2017 consolidated financial statements in accordance with Staff Accounting Bulletin No. 118, which provided SEC staff guidance for the application of ASC Topic 740, *Income Taxes*, and allowed up to one year to complete the required analyses and accounting for the TCJA. At December 31, 2017 the Company was able to make reasonable estimates of the impact of the TCJA for the reduction in the federal corporate tax rate, changes to bonus depreciation and consequences on the Company's regulatory liabilities. The accounting for the income tax effects of the enactment of the TCJA was complete as of September 30, 2018. The Company did not make any material adjustments in 2018 to the amounts recorded at December 31, 2017.

15. Asset Retirement Obligations (AROs)

The Company's AROs are related to OTP's coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

OTP recorded no new AROs in 2018.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2018 and 2017 are presented in the following table:

(in thousands)	2018	2017
Asset Retirement Obligations		
Beginning Balance	$8,719	$8,341
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Accrued Accretion	398	378
Settlements	--	--
Ending Balance	$9,117	$8,719
Asset Retirement Costs Capitalized		
Beginning Balance	$2,983	$2,983
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Settlements	--	--

Ending Balance	$2,983	$2,983
Accumulated Depreciation – Asset Retirement Costs Capitalized		
Beginning Balance	$915	$795
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	119	120
Settlements	--	--
Ending Balance	$1,034	$915

Settlements	None	None
Original Capitalized Asset Retirement Cost – Retired	$ --	$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	$ --	$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	$ --	$ --

16. Subsequent Events

Stock Incentive Awards

On February 13, 2019 the following stock incentive awards were granted to officers under the 2014 Incentive Plan:

Award	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Restricted Stock Units Granted	15,600	$49.6225	25% per year through February 6, 2023
Stock Performance Awards Granted:			
Under Executive Agreement	47,800	$42.875	December 31, 2021
Under Legacy Agreement	7,800	$45.885	December 31, 2021

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

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 return on equity. 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 EEI 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 718, and will be measured over the performance period based on the grant-date fair value of the award. The grant-date fair value of each performance share award was determined using a Monte Carlo fair valuation simulation model.

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 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.

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Supplementary Financial Information

Quarterly Information (not audited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings per common share may not equal total earnings per common share.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2018	2017	2018	2017	2018	2017	2018	2017
Operating Revenues:								
Electric:								
Revenues from contracts with Customers	$123,825	$119,782	$105,284	$102,655	$105,749	$102,923	$115,779	$111,117
Changes in Accrued Revenues under Alternative Revenue Programs	(875)	(1,239)	(1,565)	(424)	(317)	471	2,318	(779)
Total Electric Revenues	$122,950	$118,543	$103,719	$102,231	$105,432	$103,394	$118,097	$110,338
Product Sales under Contracts with Customers	118,316	95,574	122,629	109,855	122,230	113,063	103,074	96,352
Total Operating Revenues	$241,266	$214,117	$226,348	$212,086	$227,662	$216,457	$221,171	$206,690
Operating Income[1]	$37,615	$34,300	$30,105	$31,097	$38,262	$32,948	$23,407	$33,942
Net Income	$26,215	$19,585	$18,696	$16,778	$23,273	$17,734	$14,161	$18,342
Basic Earnings Per Share	$.66	$.50	$.47	$.43	$.59	$.45	$.36	$.46
Diluted Earnings Per Share	$.66	$.49	$.47	$.42	$.58	$.45	$.35	$.46
Dividends Declared Per Common Share	$.335	$.320	$.335	$.320	$.335	$.320	$.335	$.320
Average Number of Common Shares Outstanding--Basic	39,551	39,351	39,606	39,463	39,622	39,508	39,622	39,508
Average Number of Common Shares Outstanding--Diluted	39,864	39,641	39,879	39,702	39,904	39,795	39,922	39,855

[1] *With the adoption, in 2018, of accounting standard updates included in ASU 2017-07, the Company began charging nonservice cost components of postretirement benefits previously charged to operating expense to a separate expense*

line outside of and below operating income, resulting in decreased operating expenses and increased operating income. Accordingly, operating income for the 2017 quarters have been restated to reflect the reclassification of the nonservice cost components of postretirement benefits for those periods.

Item 9. **CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE**

None.

Item 9A. **CONTROLS AND PROCEDURES**

Evaluation of Disclosures Controls and Procedures**.** Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2018, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2018.

Changes in Internal Control over Financial Reporting**.** There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report Regarding Internal Control Over Financial Reporting. Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this Annual Report on Form 10-K. The consolidated financial statements of the Company have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). These internal controls are designed only to provide reasonable assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition.

Management has completed its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework*

(*2013*) to conduct the required assessment of the effectiveness of the Company’s internal control over financial reporting. Based on this assessment, management concluded that, as of December 31, 2018, the Company’s internal control over financial reporting was effective based on those criteria. The Company’s independent registered public accounting firm, Deloitte & Touche LLP, has audited the Company’s consolidated financial statements included in this Annual Report on Form 10-K and issued an attestation report on the Company’s internal control over financial reporting.

Attestation Report of Independent Registered Public Accounting Firm. The attestation report of Deloitte & Touche LLP, the Company’s independent registered public accounting firm, regarding the Company’s internal control over financial reporting is provided on page 61.

Item 9B. OTHER INFORMATION

None.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under “Election of Directors” in the Company's definitive Proxy Statement for the 2019 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A hereto. The information regarding Section 16 reporting is incorporated by reference to the information under “Security Ownership of Certain Beneficial Owners - Section 16(a) Beneficial Ownership Reporting Compliance” in the Company’s definitive Proxy Statement for the 2019 Annual Meeting. The information required by this Item regarding the Company’s procedures for recommending nominees to the board of directors is incorporated by reference to the information under “Corporate Governance - Director Nomination Process” in the Company’s definitive Proxy Statement for the 2019 Annual Meeting. The information required by this Item regarding the Audit Committee and the Company’s Audit Committee financial experts is incorporated by reference to the information under “Committees of the Board of Directors – Audit Committee” in the Company’s definitive Proxy Statement for the 2019 Annual Meeting.

The Company has adopted a code of conduct that applies to all of its directors, officers (including its principal executive officer, principal financial officer, and its principal accounting officer or controller or person performing similar functions) and employees. The Company’s code of conduct is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of conduct by posting such information on its website at the address specified above. Information on the Company’s website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

Item 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under “Compensation Discussion and Analysis,” “Report of Compensation Committee,” “Executive Compensation,” “Pay Ratio Disclosure” and “Director Compensation” in the Company's definitive Proxy Statement for the 2019 Annual Meeting.

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Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item regarding security ownership is incorporated by reference to the information under “Security Ownership of Certain Beneficial Owners” in the Company’s definitive Proxy Statement for the 2019 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2018 about the Company’s common stock that may be issued under all its equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)	
Equity compensation plans approved by security holders:					
2014 Stock Incentive Plan	356,585	(1)	$ 0.00	1,121,330	(2)
1999 Stock Incentive Plan	1,747	(3)	$ 0.00	--	(4)
1999 Employee Stock Purchase Plan	--		N/A	366,867	(5)
Equity compensation plans not approved by security holders	--		--	--	
Total	358,332		$ 0.00	1,488,197	

(1) Includes 81,000, 78,000 and 102,198 performance-based share awards granted in 2018, 2017 and 2016, respectively, 94,770 restricted stock units outstanding as of December 31, 2018, and 617 stock units as part of the

director deferred compensation program and excludes 43,225 shares of restricted stock issued under the 2014 Stock Incentive Plan.

(2) The 2014 Stock Incentive Plan provides for the issuance of any shares available under the plan in the form of restricted stock, restricted stock units, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights.

(3) Director deferred compensation program stock units under the 1999 Stock Incentive Plan.

(4) The 1999 Stock Incentive Plan provided for the issuance of any shares available under the plan in the form of restricted stock, restricted stock units, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights. The 1999 Stock Incentive Plan expired by its terms on December 13, 2013 and no more awards may be granted thereunder.

(5) Shares are issued based on employee's election to participate in the plan.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information under "Policy and Procedures Regarding Transactions with Related Persons," "Election of Directors" and "Committees of the Board of Directors" in the Company's definitive Proxy Statement for the 2019 Annual Meeting.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under "Ratification of Independent Registered Public Accounting Firm – Fees" and "Ratification of Independent Registered Public Accounting Firm – Pre-Approval of Audit/Non-Audit Services Policy" in the Company's definitive Proxy Statement for the 2019 Annual Meeting.

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PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of documents filed as part of this report:

1. *Financial Statements*

2. *Financial Statement Schedules*

SCHEDULE 1 - Condensed financial information of registrant
Otter Tail Corporation (PARENT COMPANY)
Condensed Balance Sheets, December 31

(in thousands)	**2018**	2017
Assets		
Current Assets		
Cash and Cash Equivalents	**$--**	$16,371
Accounts Receivable	**--**	--
Accounts Receivable from Subsidiaries	**1,931**	2,098
Interest Receivable from Subsidiaries	**117**	117
Notes Receivable from Subsidiaries	**1,167**	1,752
Other	**3,482**	1,130
Total Current Assets	**6,697**	21,468
Investments in Subsidiaries	**787,869**	724,613
Notes Receivable from Subsidiaries	**79,422**	79,611
Deferred Income Taxes	**21,100**	27,923
Other Assets	**31,547**	31,559
Total Assets	**$926,635**	$885,174

Liabilities and Equity		
Current Liabilities		
Short-Term Debt	**$9,215**	$--
Current Maturities of Long-Term Debt	**172**	186
Accounts Payable to Subsidiaries	**7**	6
Notes Payable to Subsidiaries	**60,626**	61,908
Other	**9,994**	7,799
Total Current Liabilities	**80,014**	69,899
Other Noncurrent Liabilities	**37,814**	38,319
Commitments and Contingencies		
Capitalization		
Long-Term Debt, Net of Current Maturities	**79,944**	80,064
Common Shareholder Equity	**728,863**	696,892
Total Capitalization	**808,807**	776,956
Total Liabilities and Equity	**$926,635**	$885,174

See accompanying notes to condensed financial statements.

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Otter Tail Corporation (PARENT COMPANY)
Condensed Statements of Income--For the Years Ended December 31

(in thousands)	**2018**	2017	2016
Operating Loss			
Revenue from Contracts with Customers	**$--**	$--	$--
Operating Expenses	**9,916**	7,138	8,530
Operating Loss	**(9,916)**	(7,138)	(8,530)
Other Income (Expense)			
Equity Income in Earnings of Subsidiaries	**91,446**	82,715	67,047
Interest Charges	**(4,043)**	(4,270)	(6,817)
Interest Charges to Subsidiaries	**(387)**	(244)	(173)
Interest Income from Subsidiaries	**2,839**	2,848	4,897
Nonservice Cost Components of Postretirement Benefits	**(1,422)**	(1,215)	(1,159)
Other Income	**550**	1,054	1,621
Total Other Income	**88,983**	80,888	65,416
Income Before Income Taxes	**79,067**	73,750	56,886
Income Tax (Benefit) Expense	**(3,278)**	1,311	(5,435)
Net Income	**$82,345**	$72,439	$62,321

See accompanying notes to condensed financial statements.

Otter Tail Corporation (PARENT COMPANY)
Condensed Statements of Cash Flows--For the Years Ended December 31

(in thousands)	**2018**	2017	2016
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	**$56,947**	$50,205	$83,296
Cash Flows from Investing Activities			
Return of Capital (Investment in Subsidiaries)	**(24,764)**	--	9,912
Debt Repaid by (Issued to) Subsidiaries	**774**	151	(3,309)
Cash (Used in) Provided by Investing Activities	**(623)**	(121)	106
Net Cash (Used in) Provided by Investing Activities	**(24,613)**	30	6,709
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**31**	--	(428)
Net Short-Term Borrowings (Repayments)	**9,215**	--	(59,666)
(Repayments to) Borrowings from Subsidiaries	**(1,281)**	23,389	(60,948)
Proceeds from Issuance of Common Stock	**--**	4,349	44,435
Common Stock Issuance Expenses	**(108)**	--	(562)
Payments for Retirement of Capital Stock	**(3,011)**	(1,799)	(104)
Proceeds from the Issuance of Long-Term Debt	**--**	--	130,000
Short-Term and Long-Term Debt Issuance Expenses	**(164)**	(158)	(723)
Payments for Retirement of Long-Term Debt	**(189)**	(15,231)	(87,547)

Dividends Paid and Other Distributions	**(53,198)**	(50,632)	(48,244)
Net Cash Used in Financing Activities	**(48,705)**	(40,082)	(83,787)
Net Change in Cash and Cash Equivalents	**(16,371)**	10,153	6,218
Cash and Cash Equivalents at Beginning of Period	**16,371**	6,218	--
Cash and Cash Equivalents at End of Period	**$--**	$16,371	$6,218

See accompanying notes to condensed financial statements.

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Otter Tail Corporation (Parent Company)

Notes to Condensed Financial Statements

For the years ended December 31, 2018, 2017 and 2016

Incorporated by reference are Otter Tail Corporation's consolidated statements of comprehensive income and common shareholders' equity in Part II, Item 8.

Basis of Presentation

The condensed financial information of Otter Tail Corporation is presented to comply with Rule 12-04 of Regulation S-X. The unconsolidated condensed financial statements do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read with the consolidated financial statements and related notes included in this Annual Report on Form 10-K.

Otter Tail Corporation's investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity income in earnings of subsidiaries.

Related Party Transactions

As of December 31, 2018: *(in thousands)*	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 1,877	$ --	$ --	$ --	$ 7	$--
Vinyltech Corporation	4	17	--	11,500	--	15,305
Northern Pipe Products, Inc.	--	8	--	5,522	--	5,623
BTD Manufacturing, Inc.	--	77	415	52,000	--	--
T.O. Plastics, Inc.	--	15	--	10,400	--	14,308
Varistar Corporation	--	--	752	--	--	25,390
Otter Tail Assurance Limited	50	--	--	--	--	--

	$ 1,931	$ 117	$ 1,167	$ 79,422	$ 7	$60,626

As of December 31, 2017: *(in thousands)*	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 2,067	$ --	$ --	$ --	$ 6	$--
Vinyltech Corporation	2	17	--	11,500	--	20,603
Northern Pipe Products, Inc.	4	8	--	5,711	--	8,186
BTD Manufacturing, Inc.	--	77	--	52,000	--	7,260
Wind Tower Business	--	--	1,461	--	--	--
Dock and Boatlift Business	--	--	291	--	--	--
T.O. Plastics, Inc.	--	15	--	10,400	--	13,446
Varistar Corporation	--	--	--	--	--	12,413
Otter Tail Assurance Limited	25	--	--	--	--	--
	$ 2,098	$ 117	$ 1,752	$ 79,611	$ 6	$61,908

Dividends

Dividends paid to Otter Tail Corporation (the Parent) from its subsidiaries were as follows:

(in thousands)	2018	2017	2016
Cash Dividends Paid to Parent by Subsidiaries	$53,134	$50,571	$77,779

See Otter Tail Corporation's notes to consolidated financial statements in Part II, Item 8 for other disclosures.

Other schedules are omitted because of the absence of the conditions under which they are required, because the amounts are insignificant or because the information required is included in the financial statements or the notes thereto.

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3. Exhibits

The following Exhibits are filed as part of, or incorporated by reference into, this report.

	Previously Filed		
	File No.	As Exhibit No.	
2-A	8-K filed 7/1/09	2.1	—Plan of Merger, dated as of June 30, 2009, by and among Otter Tail Corporation (now known as Otter Tail Power Company), Otter Tail Holding Company (now known as Otter Tail Corporation) and Otter Tail Merger Sub Inc.
2-B	10-K/A for year ended 12/31/16	2-B	—Asset Purchase Agreement, dated as of November 16, 2016, among Otter Tail Power Company, EDF Renewable Development, Inc., Power Partners Midwest, LLC, EDF-RE US Development, LLC and Merricourt Power Partners, LLC.**/***
2-C	10-K/A for year ended 12/31/16	2-C	—Turnkey Engineering, Procurement and Construction Services Agreement, dated as of November 16, 2016, between Otter Tail Power Company and EDF-RE US Development, LLC.**/***
3-A	8-K filed 7/1/09	3.1	—Restated Articles of Incorporation.
3-B	8-K filed 7/1/09	3.2	—Restated Bylaws.
4-A	8-K filed 8/23/07	4.1	—Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
4-A-1	8-K filed 12/20/07	4.3	—First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
4-A-2	8-K filed 9/15/08	4.1	—Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
4-A-3	8-K filed 7/1/09	4.2	—Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.
4-B	8-K filed 11/2/12	4.1	—Third Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Corporation, the Banks named therein, Bank of America, N.A. and JPMorgan Chase Bank, N.A., as Co-Syndication Agents, KeyBank National Association, as Documentation Agent, U.S. Bank National Association, as administration agent for the Banks and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners.
4-B-1	8-K filed 11/1/13	4.1	—First Amendment to Third Amended and Restated Credit Agreement, dated as of October 29, 2013, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West and Union Bank, N.A., as Banks.
4-B-2	8-K filed 11/4/14	4.1	—Second Amendment to Third Amended and Restated Credit Agreement, dated as of November 3, 2014, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.

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	Previously Filed		
	File No.	**As Exhibit No.**	
4-B-3	8-K filed 11/3/15	4.1	—Third Amendment to Third Amended and Restated Credit Agreement, dated as of October 29, 2015, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-B-4	8-K filed 11/3/16	4.1	—Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2016, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-B-5	8-K filed 11/2/17	4.1	—Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2017, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-B-6	8-K filed 11/6/18	4.1	—Sixth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2018, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-C	8-K filed 11/2/12	4.2	—Second Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Power Company, the Banks named therein, JPMorgan Chase Bank, N.A. and Bank of America, N.A., as Co-Syndication Agents, KeyBank National Association and CoBank, ACB, as Co-Documentation Agents, U.S. Bank National Association, as administrative agent for the Banks, and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners.
4-C-1	8-K filed 11/1/13	4.2	—First Amendment to Second Amended and Restated Credit Agreement, dated as of October 29, 2013, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association and Union Bank, N.A., as Banks.
4-C-2	8-K filed 11/4/14	4.2	—Second Amendment to Second Amended and Restated Credit Agreement, dated as of November 3, 2014, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.

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	Previously Filed File No.	As Exhibit No.	
4-C-3	8-K filed 11/3/15	4.2	—Third Amendment to Second Amended and Restated Credit Agreement, dated as of October 29, 2015, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-C-4	8-K filed 11/3/16	4.2	—Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of October 31, 2016, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-C-5	8-K filed 11/2/17	4.2	—Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of October 31, 2017, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-C-6	8-K filed 11/6/18	4.2	—Sixth Amendment to Second Amended and Restated Credit Agreement, dated as of October 31, 2018, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-D	8-K filed 8/3/11	4.1	—Note Purchase Agreement, dated as of July 29, 2011, between Otter Tail Power Company and the Purchasers named therein.
4-E	8-K filed 8/16/13	4.1	—Note Purchase Agreement dated as of August 14, 2013 between Otter Tail Power Company and the Purchasers named therein.
4-F	8-K filed 9/27/16	4.1	—Note Purchase Agreement dated as of September 23, 2016 between Otter Tail Corporation and the Purchasers named therein.
4-G	8-K filed 11/16/17	4.1	—Note Purchase Agreement dated as of November 14, 2017 between Otter Tail Power Company and the Purchasers named therein.
10-A	10-K for year ended 12/31/89	10-F	—Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970).
10-A-1	10-K for year ended 12/31/89	10-F-1	—Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-A-2	10-K for year ended 12/31/91	10-F-2	—Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-A-3	10-K for year ended 12/31/91	10-F-3	—Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-A-4	10-K for year ended	10-F-4	—Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).

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	Previously Filed File No.	As Exhibit No.	
10-A-5	10-Q for quarter ended 9/30/03	10.1	—Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-A-6	10-K for year ended 12/31/92	10-F-5	—Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-B	10-Q for quarter ended 6/30/15	10.3	—Big Stone South–Ellendale Project Ownership Agreement dated as of June 12, 2015 between Otter Tail Power Company, a wholly owned subsidiary of Otter Tail Corporation, and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.**
10-C	2-61043	5-H	—Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company and Minnesota Power & Light Company (dated as of July 1, 1977).
10-C-1	10-K for year ended 12/31/89	10-H-1	—Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-C-2	10-K for year ended 12/31/89	10-H-2	—Supplemental Agreement No. Two, dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement.
10-C-3	10-K for year ended 12/31/89	10-H-3	—Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-C-4	10-K for year ended 12/31/92	10-H-4	—Agreement, dated as of September 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No. 1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978.
10-C-5	10-Q for quarter ended 9/30/01	10-A	—Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-C-6	10-Q for quarter ended 9/30/03	10.2	—Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-D	10-K for year ended 12/31/12	10-J	—Lignite Sales Agreement between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., Northwestern Corporation, dated as of October 10, 2012.**
10-D-1	8-K filed 1/31/14	10.1	—First Amendment to Lignite Sales Agreement dated as of January 30, 2014 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.
10-D-2	8-K filed 3/18/15	10.1	—Second Amendment to Lignite Sales Agreement dated as of March 16, 2015 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.
10-E	10-Q/A for quarter ended 6/30/13	10.1	—Wind Energy Purchase Agreement dated May 9, 2013 between Otter Tail Power Company and Ashtabula Wind III, LLC.**
10-F-1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended.*

10-F-1a	10-K for year ended 12/31/10	10-N-1A	—First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*

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	Previously Filed File No.	As Exhibit No.	
10-F-1b	8-K filed 4/17/14	10.5	—Second Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10-F-2	8-K filed 2/04/05	10.1	—Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-F-2a	10-K for year ended 12/31/06	10-N-2a	—First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-F-2b	10-K for year ended 12/31/10	10-N-2B	—Second Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-F-3	10-Q for quarter ended 9/30/11	10.1	—Nonqualified Retirement Plan (2011 Restatement).*
10-F-4	10-Q for quarter ended 9/30/16	10.1	—1999 Employee Stock Purchase Plan, As Amended (2016).
10-F-5	8-K filed 4/13/06	10.4	—1999 Stock Incentive Plan, As Amended (2006).*
10-F-6	10-K for year ended 12/31/13	10-O-12	—2014 Executive Annual Incentive Plan.*
10-F-7	333-195337	4.1	—Otter Tail Corporation 2014 Stock Incentive Plan.*
10-F-8	10-K for year ended 12/31/16	10-J-14	—Summary of Non-Employee Director Compensation (2016).*
10-F-9	8-K filed 2/11/15	10.1	—Form of 2015 Performance Award Agreement (Executives).*
10-F-10	8-K filed 2/11/15	10.2	—Form of 2015 Performance Award Agreement (Legacy).*
10-F-11	8-K filed 2/11/15	10.3	—Form of 2015 Restricted Stock Unit Award Agreement (Executives).*
10-F-12	8-K filed 2/11/15	10.4	—Form of 2015 Restricted Stock Unit Award Agreement (Legacy).*
10-F-13	8-K filed 4/15/15	10.2	—Form of 2015 Restricted Stock Award Agreement for Directors.*
10-F-14	8-K filed 2/11/15	10.5	—Otter Tail Corporation Executive Restoration Plus Plan, as Amended and Restated.*
10-F-14a	10-K for year ended 12/31/17	10-F-18a	—First Amendment of Otter Tail Corporation Executive Restoration Plus Plan.*
10-F-15	10-K for year ended 12/31/17	10-F-19	—Summary of Non-Employee Director Compensation (2018).*
10-F-16	10-Q for quarter ended 03/31/18	10.1	—Form of 2018 Performance Award Agreement (Executives).*
10-F-17	10-Q for quarter ended 03/31/18	10.2	—Form of 2018 Performance Award Agreement (Legacy).*
10-F-18			—Form of 2018 Restricted Stock Award Agreement for Directors.*
10-F-19			—Summary of Non-Employee Director Compensation (2019).*
10-G	10-K for year ended 12/31/12	10-O-1	—Executive Employment Agreement, Kevin Moug.*
10-H-1	10-K for year ended 12/31/10	10-Q-3	—Change in Control Severance Agreement, Kevin G. Moug.*
10-H-2	10-K for year ended 12/31/11	10-Q-5	—Change in Control Severance Agreement, Chuck MacFarlane.*
10-H-3	10-Q for quarter ended 9/30/14	10.3	—Change in Control Severance Agreement, Timothy Rogelstad.*
10-H-4	10-Q for quarter ended 9/30/14	10.6	—Change in Control Severance Agreement, Paul Knutson.*

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	Previously Filed File No.	As Exhibit No.	
10-H-5	10-K for year ended 12/31/15	10-R-6	—Change in Control Severance Agreement, John Abbott.*
10-H-6	10-K for year ended 12/31/17	10-I-7	—Change in Control Severance Agreement, Jennifer Smestad.*
10-I	10-K for year ended 12/31/17	10-J	—Otter Tail Corporation Executive Severance Plan.*
21-A			—Subsidiaries of Registrant.
23-A			—Consent of Deloitte & Touche LLP.
24-A			—Power of Attorney.
31.1			—Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2			—Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			—Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2			—Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101			—Financial statements from the Annual Report on Form 10-K of Otter Tail Corporation for the year ended December 31, 2018, formatted in Extensible Business Reporting Language: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Common Shareholders' Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Consolidated Statements of Capitalization, (vii) the Notes to Consolidated Financial Statements and (viii) Schedule 1.

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

**Confidential information has been omitted from this Exhibit and filed separately with the Securities and Exchange Commission pursuant to a confidential treatment request under Rule 24b-2.

***Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company hereby undertakes to furnish copies of any of the omitted schedules and exhibits to the Securities and Exchange Commission upon request.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

Item 16. FORM 10-K SUMMARY

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

(authorized officer and principal financial officer)

Dated: February 22, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature and Title

Charles S. MacFarlane	)
President and Chief Executive Officer	)
(principal executive officer) and Director	)
	)
Kevin G. Moug	)
Chief Financial Officer and Senior Vice President	)
(principal financial and accounting officer)	)
	) By /s/ Charles S. MacFarlane
Nathan I. Partain	) Charles S. MacFarlane
Chairman of the Board and Director	) Pro Se and Attorney-in-Fact
	) Dated February 22, 2019
Karen M. Bohn, Director	)
	)
John D. Erickson, Director	)
	)

Steven L. Fritze, Director	)
	)
Kathryn O. Johnson, Director	)
	)
Timothy J. O'Keefe, Director	)
	)
James B. Stake, Director	)
	)
Thomas J. Webb, Director	)

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