Otter Tail Corp
Form 10-K
February 20, 2018

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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, 2017**

( ) Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _______to_______

Commission File Number **0-53713**

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

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

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark 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 or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer	Accelerated Filer
Non-Accelerated Filer	Smaller Reporting Company
(Do not check if a smaller reporting company)	Emerging Growth Company

If an emerging growth company, indicate by 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 30, 2017 was **$1,500,154,049.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **39,626,594 Common Shares ($5 par value) as of February 8, 2018.**

Documents Incorporated by Reference:

Proxy Statement for the 2018 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.

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 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
BACT	Best-Available Control Technology
BTD	BTD Manufacturing, Inc.
Btu	British Thermal Unit
CAA	Clean Air Act
CCMC	Coyote Creek Mining Company, L.L.C.
CCR	Coal Combustion Residuals
CIP	Conservation Improvement Program
CO_2	carbon dioxide
CON	Certificate of Need
CPEC	Central Power Electric Cooperative
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
Foley	Foley Company

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

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MRO	Midwest Reliability Organization
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.
NO_x	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
RSG	Revenue Sufficiency Guarantee
RTO Adder	Incentive of additional 50-basis points for Regional Transmission Organization participation
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
SF_6	sulfur hexaflouride
SO_2	sulfur dioxide
SPP	Southwest Power Pool
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 4334 18th Avenue SW, Suite 200, 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). Information on the Company's website 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 2,097 full-time employees in its continuing operations at December 31, 2017. 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.

From 2011 through 2015, the Company sold several businesses in order to realign its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations. Recent divestitures include:

In 2012 the Company completed the sale of the assets of its former wind tower company.

In 2013 the Company sold substantially all the assets of its former dock and boatlift company.

In 2015 the Company sold the assets of AEV, Inc., its former energy and electrical construction contractor and the Company sold Foley Company, its former water, wastewater, power and industrial construction contractor. With the sale of these two companies the Company eliminated its Construction segment.

On September 1, 2015 the Company acquired the assets of Impulse Manufacturing Inc. (Impulse) of Dawsonville, Georgia, now operating under the name BTD-Georgia, for $29.3 million. 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.

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.

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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.

The Company has lowered its overall risk by investing in rate base growth opportunities in its Electric segment and divesting certain nonelectric operating companies that no longer fit the Company's portfolio criteria. This strategy has provided a more predictable earnings stream, improved the Company's credit quality and preserved its ability to fund the dividend. The Company's goal is to deliver annual growth in earnings per share between four to seven percent over the next several years, using 2017 diluted earnings per share from continuing operations 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, including the 2015 acquisition of BTD-Georgia and the facilities expansion and addition of paint services at BTD Manufacturing Inc.'s Minnesota facilities completed in 2016. 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 will continue to be a fundamental part of its strategy. The actual mix of earnings from continuing operations in 2017 was 69% from the electric utility and 31% 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 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 37 through 59 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 76 through 79 of this Annual Report on Form 10-K.

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(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 51%, 53% and 52% of its consolidated operating revenues and 72%, 81% and 80% of its consolidated operating income from its Electric segment for the years ended December 31, 2017, 2016 and 2015, respectively.

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

State	2017	2016
Minnesota	52.8 %	53.0 %
North Dakota	38.5	38.4
South Dakota	8.7	8.6
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, 2017 OTP served 132,146 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant. One customer accounted for 12% of the 2017 revenue from the Electric segment.

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	2017	2016
Commercial	35.2 %	36.1 %

Residential	31.1	30.8
Industrial	31.8	31.0
All Other Sources	1.9	2.1
Total	100.0%	100.0%

Capacity and Demand

As of December 31, 2017 OTP’s owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants		
Big Stone Plant	258,100	kW
Coyote Station	149,800	
Hoot Lake Plant	139,700	
Total Baseload Net Plant	547,600	kW
Combustion Turbine and Small Diesel Units	109,900	kW
Hydroelectric Facilities	2,800	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 2017, about 56% of OTP’s retail kilowatt-hour (kwh) sales were supplied from OTP generating plants with the balance supplied by purchased power.

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In addition to the owned facilities described above, OTP had the following purchased power agreements in place on December 31, 2017:

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 2017-2018 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 2018 system demand and MISO reserve requirements.

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.

The following table shows the sources of energy used to generate OTP's net output of electricity for 2017 and 2016:

Sources	2017 Net kwhs	2016 Net kwhs

	Generated (Thousands)	% of Total kwhs Generated		Generated (Thousands)	% of Total kwhs Generated	
Subbituminous Coal	1,440,017	49.1	%	1,419,901	50.3	%
Lignite Coal	920,451	31.4		844,225	29.9	
Wind and Hydro	534,474	18.2		517,396	18.4	
Natural Gas and Oil	36,703	1.3		40,257	1.4	
Total	2,931,645	100.0	%	2,821,779	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, 2018
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

The above contracts for Big Stone Plant do not provide for 100% of Big Stone Plant’s anticipated coal needs in 2018 and 2019.

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 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 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.

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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 (Btu) for the years 2017, 2016, and 2015 was $2.224, $2.146 and $2.281, respectively.

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.

A breakdown of electric rate regulation by each jurisdiction follows:

Rates	Regulation	2017 % of Electric Revenues	2017 % of kwh Sales	2016 % of Electric Revenues	2016 % of kwh Sales
MN Retail Sales	MN Public Utilities Commission	46.4 %	54.0 %	47.5 %	54.0 %
ND Retail Sales	ND Public Service Commission	33.9	37.1	34.4	37.1
SD Retail Sales	SD Public Utilities Commission	7.7	8.9	7.8	8.9
Transmission & Wholesale	Federal Energy Regulatory Commission	12.0	--	10.3	--
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. OTP also has approved tariffs in its three service territories which allow qualifying customers to release and sell energy back to OTP when wholesale energy prices make such transactions desirable.

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 Federal Energy Regulatory Commission (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.

2017 Tax Cuts and Jobs Act (TCJA)

The TCJA reduced the Federal Income Tax rate from 35% to 21%. Currently, all OTP rates have been developed using a 35% tax rate. The Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC have all initiated dockets or proceedings to begin working with utilities to assess the impact of the lower income tax rate under the TCJA on electric rates, and to develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required its regulated utilities to make filings by January 30, 2018 and February 15, 2018, but has not made a determination on rate treatment. OTP currently has an active rate case in North Dakota and anticipates incorporating the impact of the tax changes to North Dakota rates within that proceeding. The SDPUC required initial comments by February 1, 2018 and indicated that revenues collected subsequent to December 31, 2017 would be subject to refund, pending determination of the impacts of the TCJA. OTP is still assessing these impacts and will continue to work with the respective Commissions to determine if any rate adjustments are necessary and, if so, to determine the appropriate timing and approach for making those adjustments.

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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. The Company's manufacturing and plastic pipe businesses are not subject to direct regulation by any of these agencies.

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345 kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of December 31, 2017 were approximately $90 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power – Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line was energized on September 8, 2017. OTP's capitalized costs on this project as of December 31, 2017 were approximately $73 million, which includes assets that are 100% owned by OTP.

Fargo–Monticello 345-kV Project—OTP invested approximately $81 million and has a 14.2% ownership interest in the jointly-owned assets of this 240-mile transmission line, and owns 100% of certain assets of the project. The final phase of this project was energized on April 2, 2015.

Brookings–Southeast Twin Cities 345-kV Project—OTP invested approximately $26 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of this project as an MVP under the MISO Tariff in December 2011. The final segments of this line were energized on March 26, 2015.

Big Stone Plant Air Quality Control System (AQCS)—OTP completed construction and testing of the Big Stone Plant AQCS in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. OTP's capitalized cost of the project, excluding allowance for funds used during construction, was approximately $200 million.

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

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.

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2016 General Rate Case—The MPUC rendered its final decision in OTP's 2016 general rate case in March 2017 and issued its written order on May 1, 2017. Pursuant to the order, OTP's allowed rate of return on rate base decreased from 8.61% to 7.5056% and its allowed rate of return on equity decreased from 10.74% to 9.41%. On July 6, 2017 the MPUC denied OTP's request for reconsideration of certain of the MPUC's rulings in the rate case and confirmed its May 1, 2017 order.

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 MVP projects will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers, and (2) approval of OTP's proposal to transition rate base, expenses and revenues from Environmental Cost Recovery (ECR) and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates were used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

Information on interim and final rate increases and interim revenue refunds accrued is detailed in the tables below:

($ in thousands)	Interim Rates Authorized April 14, 2016	Final Rates
Revenue Increase – Annualized based on Test Year Data	$ 16,816	$10,471
Revenue Percent Increase	9.56 %	5.34 %
Return on Rate Base	8.07 %	7.5056 %
Jurisdictional Rate Base based on Test Year Data	$ 483,000	$471,000
Return on Equity	10.40 %	9.41 %
Based on Equity to Total Capital of	52.50 %	52.50 %
Debt to Total Capital	47.50 %	47.50 %

Interim Revenue *(in thousands)*	April 16, 2016 through October 31, 2017
Billed	$ 23,289
Accrued Refund	$ 8,779
Net Interim Revenue	$ 14,510
Interest on Refundable Amount	$ 265
Final Refund	$ 9,044

The final interim rate refund, including interest was applied as a credit to Minnesota customers' electric bills beginning November 17, 2017.

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

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, the filings 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 megawatts (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 100 MW to 200 MW of wind in the 2022 to 2023 timeframe.

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The MPUC ordered OTP to file its next IRP no later than June 3, 2019.

Fuel and Purchased Power Costs Recovery—On December 19, 2017, the MPUC issued an order authorizing the implementation of a new fuel clause adjustment mechanism to be implemented July 1, 2019. Prior to implementation, OTP will be required to submit forecasted monthly fuel cost rates for the twelve-month period beginning July 1, 2019. Upon approval by the MPUC, those rates will be published in advance of each year to give customers notice of the next years' 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, need to show prudence of costs before allowed recovery of under-collections. The refund of any over-collection or recovery of any under-collection would be handled through a true-up mechanism. OTP will be working with other Minnesota utilities, the MNDOC and other stakeholders to address questions and further develop the mechanism prior to implementation.

On implementation of the order, 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 rate case or annual fuel cost adjustment filing that preceded the annual period of recovery. OTP will no longer be able to accrue revenue and a regulatory asset for fuel and purchased power costs incurred in excess of amounts it was allowed to recover unless and until recovery of those excess amounts has been granted through a true-up mechanism that will be provided for in a subsequent order to be issued by the MPUC. This mechanism for recovery of fuel and purchased power and related costs incurred to serve Minnesota customers could result in reductions in Electric segment operating income margins and variability in the Company's consolidated net income in future periods if those costs exceed forecasted costs.

Renewable Energy Standards, Conservation, Renewable Resource Riders—Minnesota law favors conservation over the addition of new 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. An existing environmental externality 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 \$9.00 to \$34.00 per ton of CO_2 commencing in 2022. The MPUC is required to annually update these estimates. The MNDOC and the Minnesota Pollution Control Agency (MPCA) have recommended the new range to be \$5.00 to \$25.00 per ton beginning in 2025. The MPUC will likely rule on this docket during the second quarter of 2018.

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 enough utility-scale solar energy credits to meet its expected 2020 Minnesota 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 sufficient renewable resources to currently comply with 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 2021. 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.

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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. 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 new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

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 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 July 9, 2015 the MPUC granted approval of OTP's 2014 financial incentive of $3.0 million along with an updated surcharge with an effective date of October 1, 2015.

Based on results from the 2015 MNCIP program year, OTP recognized a financial incentive of $4.2 million. The 2015 MNCIP program resulted in an approximate 39% increase in energy savings compared to 2014 program results. 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 an approximate 10% decrease in energy savings compared to 2016 program results. OTP will request approval for recovery of its 2017 MNCIP program costs not included in base rates, a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC by April 1, 2018.

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 is requiring 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, 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 provides 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 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 last general rate case. Additionally, following approval of the 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.

On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015. 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 MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment will result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to allocate costs between jurisdictions of the FERC MVP transmission projects in the TCR rider. OTP believes the MPUC-ordered treatment conflicts with federal authority over transmission of electricity in interstate commerce and rates for the transmission of electricity subject to the jurisdiction of the FERC as set forth in the Federal Power Act of 1935, as amended (Federal Power Act). The decision is expected in late 2018.

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 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. OTP filed its 2015 annual update on July 31, 2015, with a request to keep the 2014 annual update rate in place. On December 21, 2015 OTP filed a supplemental filing with updated financial information. 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 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.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the FCA rider or general rates. In its 2016 general rate case order issued May 1, 2017 the MPUC again denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs or through the FCA rider. Instead, the test-year costs will be recovered in general rates and variability of those costs in excess of amounts included in general rates will only be recovered to the extent actual kwh sales exceed forecasted kwh sales used to establish general rates.

Capital Structure Petition—Minnesota law requires an annual filing of a capital structure petition with the MPUC. In this filing the MPUC reviews and approves 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 September 1, 2017, allowing for an equity to total capitalization ratio between 47.4% and 58.0%, with total capitalization not to exceed $1,178,024,000 until the MPUC issues a new capital structure order for 2018. OTP is required to file its 2018 capital structure petition no later than May 1, 2018.

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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 in North Dakota for large electric generating facilities and high voltage transmission lines. 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 required to submit a ten-year 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%. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.30%. On December 20, 2017 the NDPSC approved OTP’s request for interim rates to increase annual revenue collections by $12.8 million, effective January 1, 2018. OTP used a lower rate of return on equity in the calculation of interim rates based on the rate of return on equity used in its 2018 test-year rate request.

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

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) 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. The NDPSC approved OTP’s 2014 annual update to the NDRRA, including a change in rate design from an amount per kwh consumed to a percentage of a customer’s bill, on March 25, 2015 with an effective date of April 1, 2015. 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 used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflects a reduction in the ROE component of the rate from 10.75%, approved in OTP’s most recent 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. The new NDRRA rate increased from 7.005% to 7.756% with an effective date of January 1, 2018.

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.

On August 31, 2015 OTP filed its 2015 annual update to its North Dakota TCR rider rate requesting recovery of approximately $10.2 million for 2016 compared with $8.5 million for 2015, including costs assessed by the MISO as well as costs from the Southwest Power Pool (SPP) that OTP began incurring January 1, 2016. These costs are associated with OTP’s load connected to the transmission system of Central Power Electric Cooperative (CPEC). OTP’s load became subject to SPP transmission-related charges when CPEC transmission assets were added to the SPP. The NDPSC approved OTP’s 2015 annual update to its TCR rider rate on December 16, 2015, with an effective date of January 1, 2016.

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On September 1, 2016 OTP filed its annual update to the TCR rider requesting a revenue requirement of $5.7 million, which includes a reduction of $2.6 million for a projected over-collection for 2016. Primary drivers of the 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 the next two years for purposes of reducing the volatility of the rates 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 filed a supplemental filing on November 2, 2017, reducing its revenue requirement request by $0.6 million to $8.0 million to reflect the rate of return and allocation factors used in its submitted general rate case also filed on November 2, 2017. The NDPSC approved the update for recovery of the $8.0 million revenue requirement on November 29, 2017. The new rates went into effect on January 1, 2018.

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 Toxics Standards (MATS) projects. The ECR rider provides for a return on investment at the level approved in OTP's most recent general rate case and for recovery of OTP's North Dakota share of reagent and emission allowance costs.

On March 31, 2015 OTP filed its annual update to the ECR. This update included a request to increase the ECR rider rate from 7.531% to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015, along with the approval of recovery of OTP's North Dakota jurisdictional share of Hoot Lake Plant MATS project 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 July 1, 2016. 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, 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 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.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the NDPSC to revise its FCA rider in North Dakota to include recovery of new reagent and emission allowance costs. On February 25, 2015 the NDPSC approved recovery of these costs through modification of the ECR rider, instead of recovery through the FCA as OTP had proposed. The ECR rider reagent and emissions allowance charge became effective May 1, 2015.

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.

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately $643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. 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. The SDPUC approved OTP's 2014 annual update on February 13, 2015 with an effective date of March 1, 2015. 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 reduction in the federal corporate income tax rate from 35% to 21% effective January 1, 2018. The updated revenue requirement requested is $1,778,992.

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, 2015 OTP filed its annual update to the South Dakota ECR requesting recovery of approximately $2.7 million in annual revenue. The SDPUC approved the request on October 15, 2015 with an effective date of November 1, 2015. On August 31, 2016 OTP filed its 2016 update to the ECR rider, requesting recovery of approximately $2.3 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.

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 May 1, 2015 OTP filed its 2014 South Dakota EEP Status Report, financial incentive and surcharge adjustment along with a request for approval of an incentive of $105,000 and EEP surcharge increase to $0.00152/kwh. On July 14, 2015 the SDPUC issued a written order approving OTP's 2014 EEP Status Report, incentive and surcharge increases.

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.

FERC

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

Multi-Value Transmission Projects—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.

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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%. A number of parties requested rehearing of the September 2016 order and the requests are pending FERC action.

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

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

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

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

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

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.

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North American Electric Reliability Corporation (NERC)

NERC is an international regulatory authority, subject to oversight by the FERC and governmental authorities in Canada, whose 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.

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. OTP's most recent audit began with a notification in October 2015 and MRO audit staff conducted fieldwork in January 2016. On February 3, 2017 OTP received the final audit report from the MRO audit team. The MRO found no potential violations at OTP. OTP's next audit will take place in the first quarter of 2019.

MISO

OTP is a member of the MISO. As the transmission provider and security coordinator for the region, the MISO seeks to optimize the efficiency of the interconnected system, provide regional 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 containing 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 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. 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.

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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.

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, 2017 OTP invested approximately $202 million in environmental control facilities. The 2018 and 2019 construction budgets include approximately $5 million and $4 million, respectively, for environmental equipment for existing facilities.

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 2017.

The Cross-State Air Pollution Rule (CSAPR) requires SO_2 and NO_x 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 SO_2 and NO_x 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 SO_2 compliance. Any SO_2 allowances that need to be obtained for Hoot Lake Plant will need to be from an entity in a Group 2 state. The impact of the CSAPR rule is anticipated to be minimal due to the sharp decline in Group 2 SO_2 allowance prices since 2016 and reduced dispatch of Hoot Lake Plant.

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. This was at the upper end of the range of which the EPA had proposed, which was 65 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 SO_2 at a level of 75 ppb on a 1-hour average. Designations for this standard are proceeding under several different pathways. For certain large sources as defined by 2012 emissions, 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 SO_2 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 SO_2 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 resides.

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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 April 15, 2016 the EPA issued a supplemental finding that the MATS rule continues to be "appropriate and necessary" when considering the costs of compliance. Litigation surrounding this finding is being held in abeyance while EPA considers whether it should be maintained, modified or otherwise reconsidered.

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 Regional Haze Rule requires emissions reductions from certain sources that are deemed to contribute to visibility impairment in Class I air quality areas. Based on the South Dakota Department of Environment and Natural Resources' determination and the final South Dakota Regional Haze State Implementation Plan approved by the EPA on March 29, 2012, Big Stone Plant was required to install Selective Catalytic Reduction and separated over-fire air to reduce NO_x emissions, dry flue gas desulfurization to reduce SO_2 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.

The North Dakota Regional Haze State Implementation Plan requires that Coyote Station reduce its NO_x emissions to 0.5 pounds per million Btu as calculated on a 30-day rolling average basis beginning on July 1, 2018. The control equipment was installed during a spring 2016 outage.

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 2017 these plants emitted approximately 2.9 million 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.

On June 6, 2010 the EPA published a final “tailoring rule” that phased in application of its PSD and Title V programs to GHG emission sources, including power plants. The PSD program applies to existing sources if there is a physical change or change in the method of operation of the facility that results in a significant net emissions increase of any pollutant. As a result, PSD does not apply on a set timeline as is the case with other regulatory programs, but is triggered when certain activities take place at a major source. If triggered, the owner or operator of an affected facility must undergo a review which requires, among other things, the identification and implementation of best-available control technology (BACT) for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

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In June 2012 the United States Court of Appeals for the D.C. Circuit upheld most of the EPA's rules regarding the regulation of GHGs under the CAA, including the tailoring rule. However, in October 2013 the U.S. Supreme Court granted a petition for a writ of certiorari to review the question of whether the regulation of new motor vehicle GHG emissions does in fact automatically trigger PSD and Title V regulation of GHGs for stationary sources. On June 23, 2014 the U.S. Supreme Court issued its decision that, in summary, held the EPA exceeded its statutory authority and may not require a PSD or Title V permit based solely on GHG emissions. However, the U.S. Supreme Court also said the EPA could continue to require that PSD permits for sources otherwise subject to PSD based on emissions of conventional pollutants contain limitations on GHG emissions based on the application of BACT. The EPA revised its regulations to implement this ruling and in 2016 proposed a *de minimis* level of GHG emissions below which PSD would not apply. 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 the final NSPS under section 111(b) of the CAA that requires 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 clean fuels such as natural gas. This rule was challenged by a number of parties and litigation is pending. Therefore, there is uncertainty regarding the future of the NSPS rules.

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," which is defined as:

…a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated.

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 final Section 111(d) emission guidelines for existing fossil fuel-fired power plants, termed the Clean Power Plan (CPP). The final rule 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.

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 CO_2 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 October 16, 2017 the EPA published a proposed rule to repeal the CPP, and on December 18, 2017, the EPA announced an Advance Notice of Proposed Rulemaking to solicit information in order to inform the EPA as the Agency considers proposing a future 111(d) rule that is consistent with the legal interpretation discussed in the proposed repeal rule. Therefore, there is uncertainty regarding the future of regulation of CO_2 under Section 111(d).

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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 CO_2 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 CO_2 emission. The MPUC, in its order dated December 21, 2007, established an estimate of future CO_2 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 2017 the range is $9.05 to $43.06 per ton, and the applicable effective date to begin using CO_2 costs in resource planning decisions is 2020. The MNDOC and MPCA have proposed a range of $5.00 to $25.00 per ton beginning in 2025 to be used for 2018.

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 CO_2 and certain criteria pollutants. A final order was issued on January 3, 2018. The environmental cost values for CO_2 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 55%, 77% and 83%, 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 2017 OTP decreased its overall system average CO_2 emissions intensity by approximately 26%. Further reductions are expected with the anticipated replacement of Hoot Lake Plant generation with natural gas-fired generation in the 2021 timeframe.

Conservation: Since 1992 OTP has helped its customers conserve more than 4.3 million cumulative megawatt-hours of electricity, which is roughly equivalent to the amount of electricity that 358,000 average homes would use in a year and represents approximately 352% of the annual energy sales of OTP's entire residential customer base. Additionally, OTP's conservation programs contribute 113 MW of load reduction to its system.

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. OTP is exploring options for meeting a Minnesota legislative mandate requiring Minnesota's investor-owned utilities to serve 1.5% of their Minnesota retail electric sales with solar power by 2020.

Other: OTP is a participating member of the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems program, which proactively is targeting a reduction in emissions of SF_6, a potent GHG. SF_6 has a global-warming potential 23,900 times that of CO_2. OTP participates in carbon sequestration research through the Plains CO_2 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 CO_2 emissions from stationary sources in central North America.

While the future financial impact of any proposed or pending litigation or regulation of GHG emissions is unknown at this time, any capital and operating costs incurred for additional pollution control equipment or CO_2 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 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.

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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 provided various studies with their next NPDES permit renewal application, but minimal impact is anticipated 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 will complete the 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 final rule was published on April 17, 2015. The rule requires OTP to complete certain actions, such as installing additional groundwater monitoring wells and investigating whether existing surface impoundments meet defined location restrictions, in order to determine whether existing surface impoundments should be retired or retrofitted with liners. The Big Stone Plant and Coyote Station surface impoundments are currently planned to be replaced with new ash handling technology in 2018 and 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.

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.

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Capital Expenditures

OTP is continually expanding, replacing and improving its electric facilities. During 2017 approximately $119 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2017 gross electric property additions, including construction work in progress, were approximately $699 million and gross retirements were approximately $84 million. OTP estimates that during the five-year period 2018-2022 it will invest approximately $901 million for electric construction, including:

- $302 million for renewable wind and solar energy generation projects.
- $161 million for natural gas-fired generation to replace Hoot Lake Plant capacity.
- $136 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.
- $35 million for OTP's Big Stone South–Ellendale 345 kV transmission line project.

The remainder of the 2018-2022 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, 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, 2017 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, 2017 OTP had 668 equivalent full-time employees. A total of 390 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.

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 27%, 28% and 28% of its consolidated operating revenues and 11%, 11% and 9% of its consolidated operating income from the Manufacturing segment for the years ended December 31, 2017, 2016 and 2015, 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.

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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, two customers combined accounted for 36% of the 2017 revenue of the Manufacturing segment.

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 on the basis of 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 many 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.

Backlog

The Manufacturing segment has backlog in place to support 2018 revenues of approximately $166 million compared with $118 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 2017, cash expenditures for capital additions in the Manufacturing segment were approximately $10 million. Total capital expenditures for the Manufacturing segment during the five-year period 2018-2022 are estimated to be approximately $53 million.

Employees

At December 31, 2017 the Manufacturing segment had 1,229 full-time employees. There were 1,092 full-time employees at BTD and 137 full-time employees at T.O. Plastics as of December 31, 2017.

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PLASTICS

General

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The Company derived 22%, 19% and 20% of its consolidated operating revenues and 24%, 16% and 19% of its consolidated operating income from the Plastics segment for the years ended December 31, 2017, 2016 and 2015, 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, northwestern 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 38% of the 2017 revenue of the Plastics segment.

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 on the basis of their high quality products, cost-effective production techniques and close customer relations and support.

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 four vendors that Northern Pipe and Vinyltech can source to supply their PVC resin requirements. Two vendors provided 100% of total resin purchases in 2017 and 2016. The supply of PVC resin may also be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of 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. 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.

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Capital Expenditures

Capital expenditures in the Plastics segment typically include investments in extrusion machines and support equipment. During 2017, cash expenditures for capital additions in the Plastics segment were approximately $4 million. Total capital expenditures for the five-year period 2018-2022 are estimated to be approximately $19 million to replace existing equipment.

Employees

At December 31, 2017 the Plastics segment had 161 full-time employees. Northern Pipe had 95 full-time employees and Vinyltech had 66 full-time employees as of December 31, 2017.

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.

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.

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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, 2017. 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, 2017 we were in compliance with the debt 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 us by requiring an equity-to-total-capitalization ratio between 47.4% and 58.0% based on OTP's 2017 capital structure petition. OTP's equity-to-total-capitalization ratio, including short-term debt, was 48.6% as of December 31, 2017.

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 of time, our business could be harmed.

All of 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. The efficient operation of our business is dependent on computer hardware and software systems. Information systems, both ours and those of third-parties, are vulnerable to security breach by computer hackers and cyber terrorists.

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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. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. 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. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks. 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.

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 and realign our business mix through capital projects, acquisitions and 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.

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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.

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 Otter Tail Corporation, 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 2017 one customer accounted for 12% of Electric segment revenue, two customers accounted for a total of 36% of Manufacturing segment revenue and two customers accounted for 38% 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.

A number of 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. Electric wholesale margins have been significantly and adversely affected by increased efficiencies in the MISO market. 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 businesses, 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.

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. On November 2, 2017 OTP filed a rate request with the NDPSC, which is pending. OTP is also an intervenor in a matter pending before the D.C. Circuit regarding FERC orders relating to the refund of RSG charges. 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. In addition, energy policy initiatives at the state or federal level could increase incentives for distributed generation or municipal utility ownership, or local initiatives could introduce generation or distribution requirements, that could change the current integrated utility model. 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.

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; 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 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. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks. 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.

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 supply, if available, and expose it to higher purchased power costs.

Changes to regulation of generating plant emissions, including but not limited to CO_2 emissions, could affect our operating costs and the costs of supplying electricity to our customers.

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 CO_2 emission levels, taxes on CO_2 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 new 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 and there is no legislation under active consideration at this time. The likelihood of any federal mandatory CO_2 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 U.S. Supreme Court granted a stay of the CPP. After the new administration issued an executive order directing the EPA to consider suspending, revising, or rescinding the NSPS rule and the CPP, the D.C. Circuit issued orders holding the appellate challenges to both rules in abeyance. In October 2017, the EPA published a proposed rule to repeal the CPP and intends to solicit additional information regarding climate change and GHG emissions. The fate of the former administration's GHG rules is uncertain, as is the outcome of EPA's potential GHG regulatory actions under the new administration. The final outcome of this rulemaking process could have a material adverse impact on our business and financial results.

MANUFACTURING

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

Our 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 many 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 that 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 accounted for 100% of our total purchases of PVC resin in 2017 and 2016. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of 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 a large number of 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 Steele County, North Dakota with a nameplate rating of 49,500 kW.

As of December 31, 2017 OTP’s transmission facilities, which are interconnected with lines of other public utilities, consisted of 606 pole-miles of jointly owned 345 kV lines; 494 pole-miles of 230 kV lines, of which 70 miles are jointly owned; 879 pole-miles of 115 kV lines; and 3,973 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.

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Item 3A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF FEBRUARY 20, 2018)

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 (53)	4/13/15	Present:	President and Chief Executive Officer
Kevin G. Moug (58)	4/9/01	Present:	Chief Financial Officer and Senior Vice President
Timothy J. Rogelstad (51)	4/14/14	Present:	Senior Vice President, Electric Platform
John Abbott (59)	2/11/15	Present:	Senior Vice President, Manufacturing Platform
Jennifer O. Smestad (47)	1/1/18	Present:	Vice President, General Counsel and Corporate Secretary

On April 13, 2015 Mr. MacFarlane was elected as the Company's President and Chief Executive Officer and as member of the Company's board of directors. On February 5, 2014 the Company's board of directors appointed Mr. MacFarlane, then President and Chief Executive Officer of OTP and Senior Vice President, Electric Platform of the Company, to the role of President and Chief Operating Officer of the Company, effective April 14, 2014. Mr. MacFarlane joined OTP in 2001 and had served as its President from 2003 to 2014 and its Chief Executive Officer from 2007 to 2014. He served as Senior Vice President, Electric platform of the Company from 2012 to 2014. Prior to joining OTP, Mr. MacFarlane served as Director of Electric Distribution Planning and Engineering for Xcel Energy Inc.'s multi-state service territory. He was also Director of Delivery Construction and Field Operations for Northern States Power Company prior to its merger with New Centuries Energy and becoming Xcel Energy.

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

On April 14, 2014 Timothy J. Rogelstad was appointed to succeed Mr. MacFarlane as President of OTP and Senior Vice President, Electric Platform of the Company. 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. Mr. Rogelstad is a registered professional engineer in the three states where OTP serves, Minnesota, North Dakota, and South Dakota.

On February 5, 2015 John Abbott was selected to serve as Senior Vice President, Manufacturing Platform, and President of Varistar. 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.

On December 19, 2017 the Company’s board of directors appointed Jennifer O. Smestad to the position of Vice President, General Counsel and Corporate Secretary of the Company, effective January 1, 2018, to succeed George A. Koeck, Senior Vice President, General Counsel and Corporate Secretary who retired effective December 31, 2017. 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. <u>Mine Safety Disclosures</u>

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 37 of this Annual Report on Form 10-K under the heading “Selected Financial Data,” on Page 93 under the heading “Retained Earnings and Dividend Restriction” and on Page 115 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, 2017.

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, 2012, and reinvestment of all dividends).

	2012	**2013**	**2014**	**2015**	**2016**	**2017**
OTC	**$100.00**	**$122.07**	**$134.51**	**$120.99**	**$192.46**	**$216.23**
EEI	**$100.00**	**$113.01**	**$145.68**	**$139.99**	**$164.40**	**$183.66**
NASDAQ	**$100.00**	**$133.48**	**$150.12**	**$150.84**	**$170.46**	**$206.91**

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Item 6. SELECTED FINANCIAL DATA

(thousands, except number of shareholders and per-share data)	**2017**	2016	2015	2014	2013
Revenues					
Electric	**$434,537**	$427,383	$407,131	$407,743	$373,540
Manufacturing	**229,738**	221,289	215,011	219,583	204,997
Plastics	**185,132**	154,901	157,758	172,050	164,957
Intersegment Eliminations	**(57)**	(34)	(96)	(114)	(80)
Total Operating Revenues	**$849,350**	$803,539	$779,804	$799,262	$743,414
Net Income from Continuing Operations	**$72,119**	$62,037	$58,589	$56,883	$48,595
Net Income from Discontinued Operations	**320**	284	756	840	2,270
Net Income	**$72,439**	$62,321	$59,345	$57,723	$50,865
Operating Cash Flow from Continuing Operations	**$173,603**	$163,541	$131,540	$125,769	$142,408
Operating Cash Flow - Continuing and Discontinued Operations	**173,577**	163,386	117,540	112,474	147,781
Capital Expenditures - Continuing Operations	**132,913**	161,259	160,084	163,582	159,833
Total Assets	**2,004,278**	1,912,385	1,818,683	1,738,116	1,558,190
Long-Term Debt	**490,380**	505,341	443,846	495,906	387,212
Basic Earnings Per Share - Continuing Operations *(1)*	**1.83**	1.61	1.56	1.56	1.33
Basic Earnings Per Share - Total *(1)*	**1.84**	1.62	1.58	1.58	1.39
Diluted Earnings Per Share - Continuing Operations *(1)*	**1.81**	1.60	1.56	1.55	1.33
Diluted Earnings Per Share - Total *(1)*	**1.82**	1.61	1.58	1.57	1.39
Return on Average Common Equity *(2)*	**10.6 %**	9.8 %	10.1 %	10.4 %	9.5 %
Dividends Declared Per Common Share	**1.28**	1.25	1.23	1.21	1.19
Dividend Payout Ratio	**70 %**	78 %	78 %	77 %	86 %
Common Shares Outstanding - Year End	**39,557**	39,348	37,857	37,218	36,272
Number of Common Shareholders *(3)*	**13,053**	13,805	14,062	14,134	14,252

(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 from continuing operations in 2017, 2016 and 2015 was 69%, 80% and 83%, respectively, from our electric utility business and 31%, 20% and 17%, respectively, from our manufacturing and plastic pipe businesses, including unallocated corporate costs.

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. In the period 2011 through 2015 we sold several businesses in execution of our announced strategy to realign our portfolio of businesses and refocus our capital investment in the electric utility.

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Major growth strategies and initiatives in our future include:

- Planned capital budget expenditures of up to $973 million for the years 2018 through 2022, of which $901 million are for capital projects at Otter Tail Power Company (OTP), including:
  - o $302 million for renewable wind and solar energy generation projects including the Merricourt Wind Project. In November 2016 OTP signed agreements to purchase this 150-megawatt (MW) wind farm in southeastern North Dakota that EDF Renewable Energy will design and build in 2019, subject to certain conditions.
  - o $161 million for natural gas-fired generation to replace Hoot Lake Plant capacity.
  - o $136 million for transformative technology and infrastructure projects 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.
  - o $35 million for a transmission project designated by the Midcontinent Independent System Operator, Inc. (MISO) as a Multi-Value Project (MVP).
- 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 2017:

- Our Plastics segment net income increased 104.1% to $21.7 million from $10.6 million in 2016.
- Our Manufacturing segment net income increased 94.1% to $11.1 million from $5.7 million in 2016.
- Our Electric segment net income decreased 0.8% to $49.4 million from $49.8 million in 2016.
- Our net cash from continuing operations was $173.6 million.
- Capital expenditures at OTP totaled $118.4 million as work was completed on one major MISO-designated MVP and work continued on another MISO-designated MVP.

We raised net proceeds of $4.3 million from the issuance of 112,548 shares of common stock through our stock plans.

We increased short-term borrowing by $69.5 million, retiring long-term debt and funding a portion of OTP's 2017 capital expenditures. We paid $48.2 million to repay long-term debt, including the retirement of $33.0 million of OTP's 5.95% notes due in August 2017 and the early repayment of $15.0 million of our LIBOR plus 0.90% term loan due February 5, 2018.

We paid out $50.6 million in common dividends in 2017.

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

(in thousands)	2017	2016
Operating Revenues:		
Electric	$434,506	$427,349
Manufacturing	229,712	221,289
Plastics	185,132	154,901
Total Operating Revenues	$849,350	$803,539
Net Income (Loss) From Continuing Operations:		
Electric	$49,446	$49,829
Manufacturing	11,050	5,694
Plastics	21,696	10,628
Corporate	(10,073)	(4,114)
Total Net Income From Continuing Operations	$72,119	$62,037

Revenues in each of our business segments increased in 2017 compared with 2016. Major factors contributing to the $30.2 million (19.5%) increase in Plastics segment revenues were a 7.2% increase in pounds of polyvinyl chloride (PVC) pipe sold and 11.5% increase in PVC pipe prices. Buying spurred by concerns of product shortages and production delays related to 2017 hurricanes in the Gulf of Mexico resulted in an estimated $3.4 million increase in segment net income in 2017. Manufacturing segment revenues increased $8.4 million (3.8%). Revenues at BTD Manufacturing, Inc. (BTD) showed a net increase of $5.9 million, with revenue increases at BTD's Minnesota and Georgia facilities increasing by 4.0% and 8.2%, respectively, as a result of increased product sales to manufacturers of recreational and lawn and garden equipment. Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $2.5 million as a result of significant increases in sales of life science and horticultural products. Electric segment revenues increased $7.2 million (1.7%) mainly as a result of increased transmission services revenue driven by increased investment in regional transmission lines with returns earned while the lines are under construction and increased revenues earned from the use of energized lines by other electric service providers.

The $10.1 million increase in net income from continuing operations in 2017 compared with 2016 reflects the following:

An $11.1 million increase in Plastics segment net income due to hurricane related sales, the positive effect of the 2017 Tax Cuts and Jobs Act (TCJA) tax rate reduction on the segment's deferred tax liabilities and increases in normal business sales.

A $5.4 million increase in Manufacturing segment net income, mainly due to increased sales to manufacturers of recreational and lawn and garden equipment and life science and horticultural products. BTD also benefited from the effect of the TCJA tax rate reduction on its deferred tax liabilities.

offset by:

A $0.4 million decrease in Electric segment net income due to increases in fuel and purchased power costs and higher property tax expenses, and a negative effect of the TCJA tax rate reduction on Electric segment deferred tax assets related to a portion of accrued postretirement benefit costs which are not recoverable in regulated rates.

A $6.0 million net-of-tax increase in Corporate net losses mainly as a result of the negative effect of the TCJA tax rate reduction on deferred tax assets at the holding company.

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

(in thousands)	**Decrease/(Increase)**
Electric	$ (458)
Manufacturing	2,637
Plastics	3,263
Corporate	(7,198)
Total	$ (1,756)

These are provisional amounts based on reasonable estimates reflecting the anticipated impact of the TCJA.

Following is a more detailed analysis of our operating results by business segment for the years ended December 31, 2017, 2016 and 2015, followed by a discussion of our financial position at the end of 2017 and our outlook for 2018.

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 2017, 2016 and 2015 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)*	2017	2016	2015
Operating Revenues:			
Electric	$ 31	$ 34	$ 92
Product Sales	26	--	4
Cost of Products Sold	18	6	9
Other Nonelectric Expenses	39	28	87

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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)	2017	% change	2016	% change	2015
Retail Sales Revenues	$374,931	--	$376,610	3	$364,614
Wholesale Revenues – Company Generation	5,173	13	4,584	83	2,499
Net Revenue – Energy Trading Activity	--	--	--	(100)	186
Other Revenues	54,433	18	46,189	16	39,832
Total Operating Revenues	$434,537	2	$427,383	5	$407,131
Production Fuel	59,690	9	54,792	28	42,744
Purchased Power – System Use	64,807	3	63,226	(19)	78,150
Other Operation and Maintenance Expenses	151,319	--	151,225	7	140,768
Depreciation and Amortization	53,276	(1)	53,743	20	44,786
Property Taxes	15,053	6	14,266	6	13,512
Operating Income	$90,392	--	$90,131	3	$87,171
Electric kilowatt-hour (kwh) Sales *(in thousands)*					
Retail kwh Sales	4,814,984	1	4,750,421	3	4,593,604
Wholesale kwh Sales – Company Generation	203,397	7	190,288	77	107,510
Wholesale kwh Sales – Purchased Power Resold	--	--	--	(100)	5,547
Heating Degree Days	5,931	12	5,314	(6)	5,633
Cooling Degree Days	380	(16)	451	(7)	483

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

	2017	2016	2015
Heating Degree Days	93.9%	84.1%	88.2 %
Cooling Degree Days	82.1%	97.4%	103.4%

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 2017, 2016 and 2015, and between years:

2017 vs Normal	2017 vs	2016 vs Normal	2016 vs 2015	2015 vs Normal

	2016				
Effect on Diluted Earnings Per Share	$(0.036)	$0.031	$(0.067)	$(0.023)	$(0.044)

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 Transmission Cost Recovery (TCR) rider revenues as a result of increased investment in transmission assets qualifying for revenue recovery through the TCR rider.

offset by:

A $7.1 million reduction in Minnesota Environmental Cost Recovery (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 MISO transmission tariff related to complaints currently under judicial review resulted in lower TCR revenues in Minnesota.

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A $3.7 million decrease in Minnesota Conservation Improvement Program (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.

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 increased $0.1 million as a result of:

A $3.2 million increase in labor and benefit costs due to increased wages and higher medical benefit payments.

offset by:

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.

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.

2016 Compared with 2015

The $12.0 million increase in retail revenue includes:

An $11.0 million increase in retail revenue related to a 9.56% interim rate increase implemented in April 2016 in conjunction with OTP's 2016 general rate increase request in Minnesota.

A $4.4 million increase in ECR rider revenue due to the recovery of additional investment and costs related to the operation of the air quality control system (AQCS) at Big Stone Plant that was placed in service in December 2015.

A $4.3 million increase in revenue related to an increase in retail kwh sales, mainly to pipeline customers.

A $2.2 million increase in TCR rider revenues related to increased investment in transmission plant.

A $1.7 million increase in MNCIP cost recovery revenues directly related to additional MNCIP activities.

offset by:

A $5.7 million decrease in fuel and purchased power cost recovery revenues mainly due to an 11.4% decrease in kwhs purchased partially offset by a 19.7% kwh increase in generation.

A $3.6 million reduction in interim rate revenues recorded to provide for an estimated refund related to a modification in OTP's original request and other expected outcomes in the pending Minnesota general rate case.

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A $1.6 million decrease in revenues related to decreased consumption due to milder weather in 2016, evidenced by a 5.7% reduction in heating-degree days and 6.6% reduction in cooling-degree days between the years.

A $0.6 million decrease in Renewable Resource Adjustment rider revenues in North Dakota, which were down as a result of earning more federal Production Tax Credits (PTCs) to pass back to customers due to a 3.6% increase in kwhs generated from wind turbines eligible for PTCs.

A $2.1 million increase in revenue from wholesale electric sales from company-owned generation was partially offset by a $1.5 million increase in fuel costs for wholesale generation, resulting in a $0.6 million increase in wholesale revenue net of fuel costs as increased plant availability in 2016 provided greater opportunity for OTP to respond to market demand.

Other electric revenues increased $6.4 million as a result of:

A $4.8 million increase in MISO transmission tariff revenues, mainly driven by increased investment in regional transmission lines and related returns on and recovery of Capacity Expansion 2020 and MISO-designated MVP investment costs and operating expenses.

A $3.0 million increase in MISO network integration transmission service revenues due to a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the Southwest Power Pool (SPP) in 2016.

offset by:

A $1.3 million decrease in revenue related to a reduction in integrated transmission agreement revenues from two regional transmission providers related to the curtailment of services under one agreement and the discontinuance of another agreement.

Production fuel costs increased $12.0 million as a result of a 27.1% increase in kwhs generated from our steam-powered and combustion turbine generators related to Big Stone Plant being fully operational in 2016 after the tie in of the AQCS in 2015, as well as Coyote Station being available to run at full load in 2016 after being restricted to half load in 2015 because of boiler feed water pump problems.

The cost of purchased power to serve retail customers decreased $14.9 million due to an 11.4% decrease in kwhs purchased in combination with an 8.7% decrease in the cost per kwh purchased. Greater availability of company-owned generation in 2016 reduced the need to purchase electricity to serve retail load. The decreased cost per kwh purchased was driven by lower market demand mainly resulting from milder weather in 2016 compared with 2015.

Electric operating and maintenance expenses increased $10.5 million as a result of:

$3.7 million in transmission expenses from the SPP as a result of a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the SPP in 2016.

A $1.9 million increase in pollution control reagent costs at Big Stone Plant and Coyote Station related to compliance with the Environmental Protection Agency power plant emission regulations.

A $1.7 million increase in MNCIP program expenditures related to additional MNCIP activities.

A $1.3 million increase in MISO transmission service charges due to increased transmission investment by other MISO members.

A $1.1 million increase in storm repair expenses associated with excessive storm damage in OTP’s Minnesota service area in July 2016 and in its North Dakota and South Dakota service areas in December 2016.

$0.8 million related to increases in other expense categories.

Depreciation and amortization expense increased $9.0 million mainly due to the AQCS at Big Stone Plant being placed in service in December 2015 along with increased investment in transmission assets with the final phases of the Fargo-Monticello and Brookings-Southeast Twin Cities 345-kV transmission lines placed in service near the end of the first quarter of 2015.

The $0.8 million increase in property tax expense is related to property additions in Minnesota and North Dakota in 2015.

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Manufacturing

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

(in thousands)	2017	% change	2016	% change	2015
Operating Revenues	$229,738	4	$221,289	3	$215,011
Cost of Products Sold	176,473	3	171,732	--	171,956
Other Operating Expenses	23,785	8	21,994	4	21,116
Depreciation and Amortization	15,379	(3)	15,794	33	11,853
Operating Income	$14,101	20	$11,769	17	$10,086

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, 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, Inc. (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 as a result 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 as a result of the following:

- o A $0.7 million increase in labor and benefit costs as a result of an increase in employees in a growing business.
- o A $0.4 million increase in contracted service expenditures for consulting, software and telecommunications in response to increased business needs.
- o A $0.4 million increase in property taxes.
- o 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 million due to certain assets reaching the ends of their depreciable lives in 2017. Depreciation expense at BTD was down $0.1 million year over year.

2016 Compared with 2015

The increase of $6.3 million in revenues in our Manufacturing segment in 2016 compared with 2015 relates to the following:

Revenues at BTD increased $9.8 million, including:

- o A $15.4 million increase in revenues at BTD-Georgia as a result of BTD owning and operating this plant for the entire year of 2016 compared to four months in 2015.
- o A $9.6 million increase in revenues mainly related to the production of wind tower components.

offset by:

o

A $15.2 million decrease in revenues related to lower sales to manufacturers of recreational and agricultural equipment due to softness in end markets served by those manufacturers.

Revenues at T.O. Plastics decreased $3.5 million, including:

- A $3.0 million decrease in revenue related to a continued decline in sales to a customer insourcing product into its own manufacturing facilities.

- A $0.6 million decrease in sales of horticultural products due to sales execution challenges, including lower sales to a major distributor.

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offset by:

- A net $0.1 million increase in sales of other products in the industrial and life sciences markets.

The $0.2 million decrease in cost of products sold in our Manufacturing segment includes the following:

Cost of products sold at BTD increased $1.7 million. This includes a $15.5 million increase in cost of products sold at BTD-Georgia, offset by a $13.8 million net decrease in cost of products sold at BTD's other facilities. The $13.8 million decrease is related to the decrease in sales, partially offset by an increase in costs of products sold at BTD's Illinois plant as a result of the increase in the production of wind tower components.

Cost of products sold at T.O. Plastics decreased $1.9 million related to the decrease in sales.

Gross margins at BTD were positively impacted in 2016 by changes in customer product mix between periods.

The $0.9 million increase in operating expenses in our Manufacturing segment includes the following:

Operating expenses at BTD increased $1.4 million, of which $1.2 million was due to a full year of operations at BTD-Georgia in 2016.

Operating expenses at T.O. Plastics decreased $0.4 million, primarily as a result of a $0.5 million decrease in selling expenses.

The $3.9 million increase in depreciation and amortization expenses in our Manufacturing segment includes a $2.3 million increase at BTD-Georgia and a $1.8 million increase at BTD's other plants mainly as a result of placing new assets in service in Minnesota in 2015 and 2016. Depreciation expense at T.O. Plastics decreased $0.2 million between the years.

Plastics

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

(in thousands)	2017	% change	2016	% change	2015
Operating Revenues	$185,132	20	$154,901	(2)	$157,758
Cost of Products Sold	140,107	13	123,496	--	123,085
Other Operating Expenses	11,564	23	9,402	(5)	9,849
Depreciation and Amortization	3,817	(1)	3,861	9	3,552
Operating Income	$29,644	63	$18,142	(15)	$21,272

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. The majority of U.S. PVC resin production plants are located in the Gulf Coast region. Major resin suppliers shut down production facilities which impacted raw material availability. Distributors and contractors became concerned about pipe availability. This accelerated pipe demand and created positive sales price pressure in the market. 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.

2016 Compared with 2015

The $2.9 million decrease in Plastics segment revenues is the result of an 11.2% decrease in the price per pound of pipe sold, partially offset by a 10.5% increase in pounds of pipe sold. The decline in sales price per pound is related to lower raw material prices between the periods. Increased pipe sales in the Colorado, Utah, and the South Central and Northwest regions of the United States were partially offset by decreased sales volumes in Montana, South Dakota and Minnesota. Cost of products sold increased $0.4 million due to the increase in sales volume, partly offset by a 9.2% decrease in the cost per pound of PVC pipe sold, as sales prices declined more than raw material prices. Lower margins have resulted in reduced incentive compensation, which is the primary factor contributing to the $0.4 million decrease in Plastics segment operating expenses.

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.

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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)	2017	% change	2016	% change	2015
Other Operating Expenses	$7,930	(11)	$8,896	(3)	$9,143
Depreciation and Amortization	73	55	47	(73)	172

Corporate operating expenses decreased $1.0 million 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.

Corporate operating expenses decreased $0.2 million in 2016 as compared to 2015 as a result of decreased expenditures for contracted services and a decrease in claims at our captive insurance company, partially offset by a decrease in expenses allocated to OTP.

Consolidated Interest Charges

(in thousands)	2017	% change	2016	% change	2015
Interest Charges	$29,604	(7)	$31,886	2	$31,160

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.

The $0.7 million increase in interest charges in 2016 compared with 2015 is due to an increase in interest expense on short-term debt at OTP as a result of a $24.7 million increase in OTP's daily average balance of short-term debt outstanding between the years and a $0.2 million decrease in capitalized interest expense. The increase in OTP's use of short-term borrowing is related to its increasing investment in two major MVP transmission line projects under construction.

Consolidated OTHER INCOME

(in thousands)	2017	% change	2016	% change	2015
Other Income	$2,632	(9)	$2,905	33	$2,177

Other income decreased $0.3 million in 2017 compared with 2016, mainly as a result of the receipt of $0.7 million in nontaxable corporate-owned life insurance proceeds in 2016 while no similar proceeds were received in 2017, 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.

The $0.7 million increase in other income in 2016 compared with 2015 is mainly due to proceeds from corporate-owned life insurance received in 2016.

Consolidated Income Taxes

Income tax expense - continuing operations was $27.0 million in 2017 compared with $20.1 million in 2016 and $21.6 million in 2015. Income tax expense increased $6.9 million in 2017 compared with 2016 mainly as a result of a $17.0 million increase in income from continuing operations before income taxes.

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

	For the Year Ended December 31,		
(in thousands)	2017	2016	2015
Tax Computed at Federal Statutory Rate – Continuing Operations	$34,707	$28,741	$28,081
Increases (Decreases) in Tax from:			
Federal PTCs	(7,527)	(7,175)	(6,962)
State Income Taxes Net of Federal Income Tax Expense	4,341	2,848	4,945
Section 199 Domestic Production Activities Deduction	(1,471)	(482)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)	(850)
Corporate-owned Life Insurance	(845)	(680)	(167)
Excess Tax deduction – Stock Compensation Awards	(751)	--	--
Employee Stock Ownership Plan Dividend Deduction	(509)	(537)	(560)
AFUDC - Equity	(322)	(280)	(426)
Investment Tax Credit Amortization	(164)	(350)	(571)
Differences Reversing in Excess of Federal Rates	551	77	(1,143)
Permanent and Other Differences	(1,873)	(1,231)	(705)
Effect of TCJA Tax Rate Reduction on Value of Net Deferred Tax Assets	1,756	--	--
Total Income Tax Expense – Continuing Operations	$27,043	$20,081	$21,642
Effective Income Tax Rate – Continuing Operations	27.3 %	24.5 %	27.0 %

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 increased 4.4% in 2017 compared with 2016 due to improved availability of the turbines and more favorable wind and operating conditions in 2017. OTP's kwh generation from its wind turbines eligible for PTCs increased 3.6% in 2016 compared with 2015 primarily due to higher average wind speed in 2016 compared with 2015. 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.

DISCONTINUED OPERATIONS

On April 30, 2015 we sold Foley Company (Foley) for $12.0 million in cash, plus $6.3 million in adjustments for working capital and other related items received in October 2015, less $1.0 million in selling expenses. On February 28, 2015 we sold the assets of AEV, Inc. for $22.3 million in cash, plus $0.6 million in adjustments for working capital and fixed assets received in October 2015, less $0.8 million in selling expenses. Foley and AEV, Inc were included in our Construction segment. On February 8, 2013 we completed the sale of substantially all the assets of our dock and boatlift company, formerly included in our Manufacturing segment. On November 30, 2012 we completed the sale of the assets of our wind tower manufacturing business, formerly included in our Wind Energy segment. Our Construction and Wind Energy segments were eliminated as a result of these sales.

The financial position, results of operations and cash flows of Foley, AEV, Inc., our wind tower manufacturing business and our dock and boatlift company are reported as discontinued operations in our consolidated financial statements. Following are the results of discontinued operations by entity for the years ended December 31, 2017, 2016 and 2015:

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
2017 Net (Loss) Income	$(140)	$--	$ 276	$ 184	$ --	$320
2016 Net (Loss) Income	$(114)	$(5)	$ 454	$ (51)	$ --	$284
2015 Net (Loss) Income	$(5,489)	$6,216	$ 344	$ (580)	$ 265	$756

Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges of $4.4 million in 2015.

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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.

Liquidity

The following table presents the status of our lines of credit as of December 31, 2017 and December 31, 2016:

(in thousands)	Line Limit	In Use on December 31, 2017	Restricted due to Outstanding Letters of Credit	Available on December 31, 2017	Available on December 31, 2016
Otter Tail Corporation Credit Agreement	$130,000	$--	$ --	$130,000	$130,000
OTP Credit Agreement[1]	170,000	112,371	300	57,329	127,067
Total	$300,000	$112,371	$ 300	$187,329	$257,067

[1] $100 million in outstanding borrowings under the OTP Credit Agreement were repaid on February 7, 2018 with proceeds from the issuance of $100 million of OTP's 4.07% Series 2018A Notes due February 7, 2048.

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 11, 2015 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 11, 2018. On May 11, 2015, we entered into a Distribution Agreement with J.P. Morgan Securities LLC (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million through an At-the-Market offering program. No shares were issued under this program in 2017.

Equity or debt financing will be required in the period 2018 through 2022 given the expansion plans related to our Electric segment to fund construction of new rate base investments. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

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

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2017 Cash Flows Compared with 2016 Cash Flows

The $10.1 million increase in cash provided by continuing operations between the years includes a $10.1 million increase in net income from continuing operations, 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 $27.0 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 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, offset by $1.8 million in stock repurchases related to tax withholding requirements for stock incentive awards. See note 5 to the Company's 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.

2016 Cash Flows Compared with 2015 Cash Flows

Cash provided by operating activities of continuing operations was $163.5 million in 2016 compared with $131.5 million in 2015. The $32.0 million increase in cash provided by continuing operations between the years includes a $32.8 million reduction in cash used for working capital items due to:

An $18.2 million decrease in cash used for accounts payable and other current liabilities at OTP, reflecting higher levels of payables in December 2016 for coal deliveries and transmission services related to the colder temperatures in December 2016 and the payment, in January 2015, of large billings for coal transportation, coal and power purchased in December 2014.

A $10.7 million decrease in cash used for accounts payable and other current liabilities at the plastic pipe companies related to an increase in year-end resin purchases in 2016 compared to 2015.

A $7.3 million decrease in cash used for interest payable and income taxes receivable between the years, mainly related to having made a $4.0 million estimated tax payment in December 2015 that was refunded in the first quarter of 2016, as a five-year extension of bonus depreciation for income taxes, approved on December 18, 2015, resulted in a lower federal income tax liability for the Company in 2015.

offset by:

A $2.3 million increase in unbilled revenues at OTP between the years resulting from the 2016 increase in interim rates in Minnesota and increased kwh sales due to colder weather in December 2016 compared with December 2015.

In continuing operations, net cash used in investing activities was $159.3 million in 2016 compared with $193.6 million in 2015. The $34.3 million decrease in cash used for investing activities includes a $32.3 million decrease in cash used in acquisitions as we paid $30.8 million to acquire the assets of BTD-Georgia in September 2015 and received a purchase price adjustment of $1.5 million in June 2016.

Net cash used in financing activities of continuing operations was $4.1 million in 2016 compared with net cash provided by financing activities of $38.1 million in 2015. Financing activities in 2016 included:

$80.0 million in proceeds from the issuance of our 3.55% Guaranteed Senior Notes due December 15, 2026 in December 2016.

$50.0 million borrowed under our term loan agreement in February 2016.

$32.8 million in net proceeds from the issuance of 1,014,115 shares of common stock under the Company’s At-the-Market offering program.

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- $11.1 million in net proceeds from the issuance of 356,399 shares of common stock under the Company's automatic dividend reinvestment and share purchase plan.

offset by:

- The repayment of the $52.3 million balance of our 9.000% notes due in December 2016.
- A $41.2 million reduction of short-term borrowings and checks written in excess of cash.
- The repayment of $35.0 million of funds borrowed in February 2016 under our term loan agreement.
- $48.2 million in common stock dividend payments.

The outstanding short-term borrowings that were paid down were, in part, used to fund the expansion of BTD's Minnesota facilities in 2015 and the September 1, 2015 acquisition of BTD-Georgia.

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 $132.9 million in 2017, $161.3 million in 2016 and $160 million in 2015. Estimated capital expenditures for 2018 are $110 million. Total capital expenditures for the five-year period 2018 through 2022 are estimated to be approximately $973 million, including:

$302 million for renewable wind and solar energy generation projects.
$161 million for natural gas-fired generation to replace Hoot Lake Plant capacity.
$136 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.
$35 million for OTP's Big Stone South–Ellendale 345 kV transmission line project.

The breakdown of 2015, 2016 and 2017 actual cash used for capital expenditures and 2018 through 2022 estimated capital expenditures by segment is as follows:

(in millions)	2015	2016	2017	2018	2019	2020	2021	2022	2018-2022
Electric	$136	$150	$119	$95	$382	$185	$145	$94	$ 901
Manufacturing	20	8	10	11	10	11	10	11	53
Plastics	4	3	4	4	4	4	4	3	19
Total	$160	$161	$133	$110	$396	$200	$159	$108	$ 973

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On November 16, 2016 OTP entered into an Asset Purchase Agreement (the Purchase Agreement) with EDF Renewable Development, Inc. and certain of its affiliated companies (EDF) to purchase and assume the development assets associated with a 150-MW wind farm in southeastern North Dakota (the Merricourt Project) for a purchase price of $34.7 million, subject to adjustments for interconnection costs. The Purchase Agreement is currently expected to close no earlier than mid-2018, pending regulatory reviews, satisfactory interconnection costs and other conditions. On the same day, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement with EDF that will be effective upon the closing of the Purchase Agreement pursuant to which EDF will construct the wind farm with a targeted completion date in 2019 for consideration of $200.5 million, subject to certain adjustments, payable following the closing of the Purchase Agreement in installments in connection with certain project construction milestones. The agreements contain representations, warranties, covenants and indemnities customary to transactions of this type and include provisions for liquidated damages to be paid by EDF in the event of certain occurrences described in the agreements. As of December 31, 2017 OTP had capitalized approximately $4.5 million in development costs associated with the Merricourt Project. On April 10, 2017 OTP submitted an application for Advance Determination of Prudence (ADP) and Certificate of Public Convenience and Necessity to the North Dakota Public Service Commission (NDPSC) for the Merricourt Project. A final order for the ADP, subject to qualifications and compliance obligations, and the Certificate of Public Convenience and Necessity was issued by the NDPSC on November 3, 2017. On October 26, 2017 the MNPUC approved the facility under the Renewable Energy Standard making the project eligible for cost recovery under the Minnesota Renewable Resource Recovery rider.

In addition to initiation of the Merricourt Project, OTP is moving forward with plans for the development, construction and ownership of a 250-MW simple-cycle natural gas-fired combustion turbine generation facility near Astoria, South Dakota (Astoria Station) as part of its plan to reliably meet customers' electric needs, replace expiring capacity purchase agreements and prepare for the planned retirement of its Hoot Lake Plant in 2021. OTP expects the project will cost approximately $165 million. As of December 31, 2017 OTP had capitalized approximately $3.8 million in development costs associated with Astoria Station. On April 10, 2017 OTP also submitted an application for ADP to the NDPSC for the Astoria Station. A final order for the ADP for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations.

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

Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2017, plus our debt and interest obligations on the $100 million in debt OTP issued on February 7, 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 (required minimums)	$644	$26	$45	$45	$528
Debt Obligations	593	--	--	171	422
Interest on Debt Obligations	433	29	58	51	295
Capacity and Energy Requirements	253	24	50	25	154
Postretirement Benefit Obligations	112	6	11	12	83
Other Purchase Obligations	48	29	17	2	--
Operating Lease Obligations	34	6	10	5	13
Total Contractual Cash Obligations	$2,117	$120	$191	$311	$1,495

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 2018 through 2022 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.

Under our shelf registration statement filed with the SEC 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, until May 11, 2018.

Under our At-the-Market offering program, we may offer and sell our common shares from time to time until May 11, 2018 through JPMS, as our distribution agent, up to an aggregate sales price of $75 million, of which $39.2 million remained available at December 31, 2017. Under the Distribution Agreement with JPMS, we will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. We are not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement.

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2017 and December 31, 2016:

(in thousands)	Line Limit	In Use on December 31, 2017	Restricted due to Outstanding Letters of Credit	Available on December 31, 2017	Available on December 31, 2016
Otter Tail Corporation Credit Agreement	$130,000	$--	$ --	$130,000	$130,000

OTP Credit Agreement[1]	170,000	112,371	300	57,329	127,067
Total	$300,000	$112,371	$ 300	$187,329	$257,067

[1] $100 million in outstanding borrowings under the OTP Credit Agreement were repaid on February 7, 2018 with proceeds from the issuance of $100 million of OTP's 4.07% Series 2018A Notes due February 7, 2048.

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was $15,169,000 on April 3, 2017 and the average daily balance of debt outstanding during 2017 was $2,305,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2017 was 2.8% compared with 2.3% in 2016. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was $112,371,000 from December 29-31, 2017 and the average daily balance of debt outstanding during 2017 was $69,391,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2017 was 2.4% compared with 1.8% in 2016. The maximum amount of consolidated short-term debt outstanding in 2017 was $112,371,000 from December 29-31, 2017 and the average daily balance of consolidated short-term debt outstanding during 2017 was $71,696,000. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2017 was 2.7%.

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $130 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 31, 2017 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of certain of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.50%, subject to adjustment based on our senior unsecured credit ratings or the issuer rating if a rating is not provided for the senior unsecured credit. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation (Varistar) and its subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

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

Long-Term Debt

2018 Note Purchase Agreement

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

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

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

2016 Note Purchase Agreement

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

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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 bemade 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.

Term Loan Agreement

On February 5, 2016 we borrowed $50 million under an unsecured Term Loan Agreement (the Term Loan Agreement) at an interest rate based on the 30 day LIBOR plus 90 basis points. The proceeds from the Term Loan Agreement were used to pay down borrowings under the Otter Tail Corporation Credit Agreement that were used to fund the expansion of BTD's Minnesota facilities in 2015 and to fund the September 1, 2015 acquisition of BTD-Georgia. We repaid $35 million of the $50 million in the fourth quarter of 2016 and we repaid the remaining $15 million during 2017. The Term Loan Agreement terminated on February 5, 2018.

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, 2017.

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

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

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

Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis). As of December 31, 2017 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement and the 2016 Note Purchase Agreement was 4.47 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, 2017 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 3.62 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, 2017 our ratio of Interest-bearing Debt to Total Capitalization was 0.46 to 1.00 on a consolidated basis and 0.49 to 1.00 for OTP. Neither Otter Tail Corporation nor OTP had any Priority Indebtedness outstanding as of December 31, 2017.

Our ratio of earnings to fixed charges from continuing operations reported in Exhibit 12.1 to this Annual Report on Form 10-K, which includes imputed finance costs on operating leases, was 4.1x for 2017 and 3.4x for 2016. During 2018, we expect this coverage ratio to increase, assuming 2018 net income meets our expectations.

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OFf-Balance-Sheet Arrangements

We and our subsidiary companies have outstanding letters of credit totaling $3.9 million, but our line of credit borrowing limits are only restricted by $0.3 million in outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2018 BUSINESS OUTLOOK

We anticipate 2018 diluted earnings per share to be in the range of $1.80 to $1.95. This guidance reflects the current mix of businesses we own, strategies for improving future operating results, the cyclical nature of some of our businesses, and current regulatory factors and economic challenges facing our Electric, Manufacturing and Plastics segments. Due to the tax rate reduction in the TCJA, we expect 2018 earnings for our Manufacturing and Plastics segments to be positively impacted by $0.09 per share offset by $0.04 per share in our corporate cost center. We expect capital expenditures for 2018 to be $110 million compared with actual cash used for capital expenditures of $133 million in 2017. Our planned expenditures for 2018 include $33 million for the Big Stone South–Ellendale transmission line project, which positively impacts earnings by providing an immediate return on invested funds through rider recovery mechanisms.

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

	2017 EPS by Segment			2018 EPS Guidance	
	GAAP-Basis	Impact of Tax Reform	*Before Impact of Tax Reform*[1]	Low	High
Electric	$1.24	$ 0.02	$ 1.26	$1.34	$1.37
Manufacturing	$0.28	$ (0.07)	$ 0.21	$0.26	$0.30
Plastics	$0.54	$ (0.08)	$ 0.46	$0.36	$0.40
Corporate	$(0.25)	$ 0.18	$ (0.07)	$(0.16)	$(0.12)
Total – Continuing Operations	$1.81	$ 0.05	$ 1.86	$1.80	$1.95
Return on Equity	10.6 %		10.8 %	10.1 %	10.9 %

1 *This table includes measures of financial performance and presentations of financial information that are not defined by generally accepted accounting principles (GAAP). Management believes that presenting diluted earnings per share from continuing operations by segment and in total on a Non-GAAP basis by excluding the impact of the TCJA tax rate reduction on deferred tax values will assist investors in making an evaluation of our performance against expectations for 2018 on a comparable basis. Management understands that there are material limitations on the use of non-GAAP measures. Non-GAAP measures are not substitutes for GAAP measures for the purpose of analyzing financial performance. These non-GAAP measures are not in accordance with, or an alternative for, measures prepared in accordance with generally accepted accounting principles and may be different from non-GAAP measures used by other companies. In addition, these non-GAAP measures are not based on any comprehensive set of accounting rules or principles. This information should not be construed as an alternative to the reported results, which have been determined and provided in accordance with GAAP.*

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

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

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

- Constructive outcome of a rate case filed in North Dakota on November 2, 2017 with a full year of increased interim rates in 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.

- Increase in transmission investments and other revenues.

offset by:

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

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

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

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

- Sales at BTD are expected to be flat year-over-year however, earnings are expected to improve based on stronger year-over-year operating margins achieved through cost reductions and improved productivity.

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

- Lower income taxes of approximately $0.04 per share as a result of the lower federal tax rates implemented as part of the TCJA.

- Backlog for the manufacturing companies of approximately $166 million for 2018 compared with $118 million one year ago.

We expect 2018 net income from the Plastics segment to be lower than 2017, because 2017 results included sales driven by customer reaction to the hurricanes that occurred in the Gulf of Mexico. This had an estimated impact on earnings of $0.09 per diluted share in 2017. We also expect lower operating margins in 2018 due to a lower expected sales prices and increasing resin prices on similar sales volumes in 2018 compared to 2017 excluding the effect of the hurricanes on 2017 sales. Plastics net income for 2018 will be positively affected by lower effective tax rates in 2018 as a result of the TCJA.

Corporate costs, net of tax, are expected to be higher in 2018 than in 2017 when excluding the effect of the TCJA on 2017 net losses in the corporate cost center. The higher net-of-tax costs expected in 2018 are due, in part, to the lower tax rate that will be in effect in 2018.

The impact of the TCJA on future results are based on reasonable estimates reflecting the anticipated impact of the TCJA, and are subject to adjustment upon obtaining additional information or to reflect future changes resulting from future legislation, rules, regulations or interpretations impacting the TCJA. The Company will continue to analyze the impact of the TCJA to assess the full effects on the Company’s future business and results.

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

(in millions)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital Expenditures:							
Electric Segment:							
Renewables and Natural Gas Generation		$1	$308	$102	$50	$1	$462
Transformative Technology and Infrastructure		--	22	32	43	39	136
Transmission		45	12	9	7	7	80
Other		49	40	42	45	47	223
Total Electric Segment	$119	$95	$382	$185	$145	$94	$901
Manufacturing and Plastics Segments	14	15	14	15	14	14	72
Total Capital Expenditures	**$133**	**$110**	**$396**	**$200**	**$159**	**$108**	**$973**
Total Electric Utility Average Rate Base	**$1,055**	**$1,091**	**$1,297**	**$1,480**	**$1,568**	**$1,625**	

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

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2018 through 2022 timeframe.

Our outlook for 2018 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.

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Critical Accounting Policies Involving Significant Estimates

Our significant accounting policies are described in note 1 to our 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 10 to our consolidated financial statements.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 35 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 2018 for our noncontributory funded pension plan is expected to be $6.6 million compared to $5.9 million in 2017, reflecting a decrease in the estimated discount rate used to determine annual benefit cost accruals from 4.60% in 2017 to 3.90% in 2018. The assumed rate of return on pension plan assets will remain at 7.50% in 2018. 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 2017, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2017 pension benefit cost by $904,000; a 0.25 decrease in the discount rate would have increased our 2017 pension benefit cost by $950,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2017 pension benefit cost by $555,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2017 pension benefit cost by $543,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2017 pension benefit cost by $641,000.

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 2017 postretirement medical benefit costs by $217,000. A 0.25 decrease in the discount rate would have increased our 2017 postretirement medical benefit costs by $228,000. See note 10 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.

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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, 2017 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of 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.

Asset Impairment

We are required to test for asset impairment relating to property and equipment whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset may exceed its fair value and not be recoverable. We apply the accounting guidance under ASC 360-10-35, *Property, Plant, and Equipment – Subsequent Measurement*, in order to determine whether or not an asset is impaired. This standard requires an impairment analysis when indicators of impairment are present. If such indicators are present, the standard requires that if the sum of the future expected cash flows from a company's asset, undiscounted and without interest charges, is less than the carrying amount, an asset impairment must be recognized in the financial statements. The amount of the impairment is the difference between the fair value of the asset and the carrying amount of the asset.

We believe the accounting estimates related to an asset impairment are critical because: (1) they are highly susceptible to change from period to period, reflecting changing business cycles, (2) they require management to make assumptions about future cash flows over future years, and (3) the impact of recognizing an impairment could have a significant effect on operations. Management's assumptions about future cash flows require significant judgment because actual operating levels have fluctuated in the past and are expected to continue to do so in the future.

As of December 31, 2017 an assessment of the carrying amounts of our long-lived assets and other intangibles indicated these assets were not impaired.

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, 2017, the fair value substantially exceeded the carrying value at all our reporting units reported under continuing operations.

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 weighted 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.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2017 we had exposure to market risk associated with interest rates because OTP had $112.4 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under the OTP Credit Agreement.

All of our remaining consolidated long-term debt outstanding on December 31, 2017 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 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, 2017 and 2016, and 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, 2017, 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, 2017, 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 Otter Tail Corporation and subsidiaries as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017, 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, 2017, 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.

Minneapolis, Minnesota

February 20, 2018

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

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Otter Tail Corporation
Consolidated Balance Sheets, December 31

(in thousands)	**2017**	2016
Assets		
Current Assets		
Cash and Cash Equivalents	$***16,216***	$--
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $1,094 for 2017 and $1,246 for 2016)	***68,466***	*68,242*
Other	***7,761***	*5,850*
Inventories	***88,034***	*83,740*
Unbilled Revenues	***22,427***	*20,080*
Income Taxes Receivable	***1,181***	*662*
Regulatory Assets	***22,551***	*21,297*
Other	***12,491***	*8,144*
Total Current Assets	***239,127***	*208,015*
Investments	***8,629***	*8,417*
Other Assets	***36,006***	*34,104*
Goodwill	***37,572***	*37,572*
Other Intangibles–Net	***13,765***	*14,958*
Regulatory Assets	***129,576***	*132,094*
Plant		
Electric Plant in Service	***1,981,018***	*1,860,357*
Nonelectric Operations	***216,937***	*211,826*
Construction Work in Progress	***141,067***	*153,261*
Total Gross Plant	***2,339,022***	*2,225,444*
Less Accumulated Depreciation and Amortization	***799,419***	*748,219*
Net Plant	***1,539,603***	*1,477,225*
Total Assets	$***2,004,278***	$*1,912,385*

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Consolidated Balance Sheets, December 31

(in thousands, except share data)	**2017**	2016
Liabilities and Equity		
Current Liabilities		
Short-Term Debt	***$112,371***	*$42,883*
Current Maturities of Long-Term Debt	***186***	*33,201*
Accounts Payable	***84,185***	*89,350*
Accrued Salaries and Wages	***21,534***	*17,497*
Accrued Taxes	***16,808***	*16,000*
Regulatory Liabilities	***9,688***	*3,294*
Other Accrued Liabilities	***11,389***	*12,083*
Liabilities of Discontinued Operations	***492***	*1,363*
Total Current Liabilities	***256,653***	*215,671*
Pensions Benefit Liability	***109,708***	*97,627*
Other Postretirement Benefits Liability	***69,774***	*62,571*
Other Noncurrent Liabilities	***22,769***	*21,706*
Commitments and Contingencies (note 8)		
Deferred Credits		
Deferred Income Taxes	***100,501***	*226,591*
Deferred Tax Credits	***21,379***	*22,849*
Regulatory Liabilities	***232,893***	*82,433*
Other	***3,329***	*7,492*
Total Deferred Credits	***358,102***	*339,365*
Capitalization (page 67)		
Long-Term Debt—Net	***490,380***	*505,341*
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, 2017—39,557,491 Shares; 2016—39,348,136 Shares	***197,787***	*196,741*
Premium on Common Shares	***343,450***	*337,684*
Retained Earnings	***161,286***	*139,479*
Accumulated Other Comprehensive Loss	***(5,631)***	*(3,800)*
Total Common Equity	***696,892***	*670,104*
Total Capitalization	***1,187,272***	*1,175,445*

Total Liabilities and Equity	**$*2,004,278***	$*1,912,385*

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)	**2017**	2016	2015
Operating Revenues			
Electric	**$434,506**	$427,349	$407,039
Product Sales	**414,844**	376,190	372,765
Total Operating Revenues	**849,350**	803,539	779,804
Operating Expenses			
Production Fuel – Electric	**59,690**	54,792	42,744
Purchased Power – Electric System Use	**64,807**	63,226	78,150
Electric Operation and Maintenance Expenses	**151,319**	151,225	140,768
Cost of Products Sold (depreciation included below)	**316,562**	295,222	295,032
Other Nonelectric Expenses	**43,240**	40,264	40,021
Depreciation and Amortization	**72,545**	73,445	60,363
Property Taxes – Electric	**15,053**	14,266	13,512
Total Operating Expenses	**723,216**	692,440	670,590
Operating Income	**126,134**	111,099	109,214
Interest Charges	**29,604**	31,886	31,160
Other Income	**2,632**	2,905	2,177
Income Before Income Taxes – Continuing Operations	**99,162**	82,118	80,231
Income Tax Expense – Continuing Operations	**27,043**	20,081	21,642
Net Income from Continuing Operations	**72,119**	62,037	58,589
Discontinued Operations			
Income (Loss) – net of Income Tax Expense (Benefit) of $213 in 2017, $138 in 2016, and ($1,539) in 2015	**320**	284	(5,404)
Impairment Loss – net of Income Tax (Benefit) of $0 in 2015	**--**	--	(1,000)
Gain on Disposition – net of Income Tax Expense of $4,530 in 2015	**--**	--	7,160
Net Income from Discontinued Operations	**320**	284	756
Total Net Income	**$72,439**	$62,321	$59,345
Average Number of Common Shares Outstanding–Basic	**39,457**	38,546	37,495
Average Number of Common Shares Outstanding–Diluted	**39,748**	38,731	37,668
Basic Earnings Per Common Share:			
Continuing Operations	**$1.83**	$1.61	$1.56
Discontinued Operations	**$0.01**	$0.01	$0.02
	$1.84	$1.62	$1.58
Diluted Earnings Per Common Share:			
Continuing Operations	**$1.81**	$1.60	$1.56
Discontinued Operations	**$0.01**	$0.01	$0.02
	$1.82	$1.61	$1.58
Dividends Declared Per Common Share	**$1.28**	$1.25	$1.23

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)	**2017**	2016	2015
Net Income	**$*72,439***	$*62,321*	$*59,345*
Other Comprehensive Income (Loss):			
Unrealized Loss on Available-for-Sale Securities:			
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	***(15)***	*(3)*	*(3)*
Gains (Losses) Arising During Period	***115***	*(14)*	*(49)*
Income Tax (Expense) Benefit	***(35)***	*6*	*18*
Change in Unrealized Losses on Available-for-Sale Securities – net-of-tax	***65***	*(11)*	*(34)*
Pension and Postretirement Benefit Plans:			
Actuarial (Losses) Gains Net of Regulatory Allocation Adjustment	***(3,791)***	*(445)*	*510*
Amortization of Unrecognized Postretirement Benefit Costs (note 10)	***629***	*628*	*821*
Income Tax Benefit (Expense)	***1,266***	*(74)*	*(532)*
Pension and Postretirement Benefit Plans – net-of-tax	***(1,896)***	*109*	*799*
Total Other Comprehensive Income (Loss)	***(1,831)***	*98*	*765*
Total Comprehensive Income	**$*70,608***	$*62,419*	$*60,110*

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, 2014	***37,218,053***	**$*186,090***	**$*278,436***	**$*112,903***	**$ *(4,663*) (a)**	**$*572,766***
Common Stock Issuances, Net of Expenses	*690,485*	*3,453*	*14,715*			*18,168*
Common Stock Retirements	*(51,352)*	*(257)*	*(1,339)*			*(1,596)*
Net Income				*59,345*		*59,345*
Other Comprehensive Income					*765*	*765*
Tax Benefit – Stock Compensation			*82*			*82*
Employee Stock Incentive Plan Expense			*1,716*			*1,716*
Common Dividends ($1.23 per share)				*(46,223)*		*(46,223)*
Balance, December 31, 2015	***37,857,186***	**$*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	*(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	*(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***

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

(in thousands)	**2017**	2016	2015
Unrealized Gain (Loss) on Marketable Equity Securities:			
Before Tax	**$*71***	$*(29)*	$*(12)*
Tax Effect	***(25)***	*10*	*4*
Unrealized Gain (Loss) on Marketable Equity Securities – net-of-tax	***46***	*(19)*	*(8)*

Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits:			
Before Tax	***(9,462)***	*(6,300)*	*(6,484)*
Tax Effect	***3,785***	*2,519*	*2,594*
Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits – net-of-tax	***(5,677)***	*(3,781)*	*(3,890)*
Accumulated Other Comprehensive Loss:			
Before Tax	***(9,391)***	*(6,329)*	*(6,496)*
Tax Effect	***3,760***	*2,529*	*2,598*
Net Accumulated Other Comprehensive Loss	**$*(5,631)***	$*(3,800)*	$*(3,898)*

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)	**2017**	2016	2015
Cash Flows from Operating Activities			
Net Income	**$*72,439***	$*62,321*	$*59,345*
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Net Gain from Sale of Discontinued Operations	**--**	--	*(7,160)*
Net (Income) Loss from Discontinued Operations	***(320)***	*(284)*	*6,404*
Depreciation and Amortization	***72,545***	*73,445*	*60,363*
Deferred Tax Credits	***(1,470)***	*(1,657)*	*(1,878)*
Deferred Income Taxes	***24,001***	*19,124*	*26,027*
Change in Deferred Debits and Other Assets	***(2,173)***	*(10,090)*	*11,407*
Discretionary Contribution to Pension Fund	**--**	*(10,000)*	*(10,000)*
Change in Noncurrent Liabilities and Deferred Credits	***19,257***	*14,685*	*20,524*
Allowance for Equity/Other Funds Used During Construction	***(986)***	*(857)*	*(1,303)*
Change in Derivatives Net of Regulatory Deferral	**--**	--	*(14,736)*
Stock Compensation Expense – Equity Awards	***3,642***	*3,178*	*1,716*
Other—Net	***10***	*7*	*(80)*
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	***(2,135)***	*(944)*	*(1,746)*
Change in Inventories	***(4,294)***	*1,874*	*1,960*
Change in Other Current Assets	***(3,060)***	*(2,541)*	*(210)*
Change in Payables and Other Current Liabilities	***(2,667)***	*11,941*	*(15,150)*
Change in Interest Payable and Income Taxes Receivable/Payable	***(1,186)***	*3,339*	*(3,943)*
Net Cash Provided by Continuing Operations	***173,603***	*163,541*	*131,540*
Net Cash Used in Discontinued Operations	***(26)***	*(155)*	*(14,000)*
Net Cash Provided by Operating Activities	***173,577***	*163,386*	*117,540*
Cash Flows from Investing Activities			
Capital Expenditures	***(132,913)***	*(161,259)*	*(160,084)*
Proceeds from Disposal of Noncurrent Assets	***4,491***	*4,837*	*3,590*
Acquisition Purchase Price Cash Received (Paid)	**--**	*1,500*	*(30,806)*
Cash Used for Investments and Other Assets	***(4,168)***	*(4,402)*	*(6,302)*
Net Cash Used in Investing Activities – Continuing Operations	***(132,590)***	*(159,324)*	*(193,602)*
Net Proceeds from Sale of Discontinued Operations	**--**	--	*39,401*
Net Cash Used in Investing Activities – Discontinued Operations	**--**	--	*(1,769)*
Net Cash Used in Investing Activities	***(132,590)***	*(159,324)*	*(155,970)*
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	***2,434***	*(3,363)*	*2,857*
Net Short-Term Borrowings (Repayments)	***69,488***	*(37,789)*	*69,818*
Proceeds from Issuance of Common Stock – net of Issuance Expenses	***4,349***	*43,873*	*13,782*
Payments for Retirement of Capital Stock	***(1,799)***	*(104)*	*(1,596)*
Proceeds from Issuance of Long-Term Debt	**--**	*130,000*	--
Short-Term and Long-Term Debt Issuance Expenses	***(380)***	*(888)*	*(312)*
Payments for Retirement of Long-Term Debt	***(48,231)***	*(87,547)*	*(212)*
Dividends Paid and Other Distributions	***(50,632)***	*(48,244)*	*(46,223)*
Net Cash (Used in) Provided by Financing Activities – Continuing Operations	***(24,771)***	*(4,062)*	*38,114*

Net Cash Provided by Financing Activities – Discontinued Operations	**--**	--	*316*
Net Cash (Used in) Provided by Financing Activities	***(24,771*** **)**	*(4,062*)	*38,430*
Net Change in Cash and Cash Equivalents	***16,216***	--	--
Cash and Cash Equivalents at Beginning of Period	**--**	--	--
Cash and Cash Equivalents at End of Period	**$*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)	**2017**	2016
Short-Term Debt		
Otter Tail Corporation Credit Agreement	**$--**	$--
Otter Tail Power Company Credit Agreement	***112,371***	*42,883*
Total Short-Term Debt	**$*112,371***	$*42,883*
Long-Term Debt		
Obligations of Otter Tail Corporation		
Term Loan, LIBOR plus 0.90%, due February 5, 2018	**$--**	$*15,000*
3.55% Guaranteed Senior Notes, due December 15, 2026	***80,000***	*80,000*
North Dakota Development Note, 3.95%, due April 1, 2018	***27***	*106*
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	***684***	*836*
Total – Otter Tail Corporation	***80,711***	*95,942*
Less: Current Maturities--net of Unamortized Debt Issuance Costs	***186***	*231*
Unamortized Long-Term Debt Issuance Costs	***461***	*539*
Total Otter Tail Corporation Long-Term Debt net of Unamortized Debt Issuance Costs	***80,064***	*95,172*
Obligations of Otter Tail Power Company		
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	**--**	*33,000*
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*
Total – Otter Tail Power Company	***412,000***	*445,000*
Less: Current Maturities--net of Unamortized Debt Issuance Costs	**--**	*32,970*
Unamortized Long-Term Debt Issuance Costs	***1,684***	*1,861*
Total Otter Tail Power Company Long-Term Debt net of Unamortized Debt Issuance Costs	***410,316***	*410,169*
Total Consolidated Long-Term Debt	***492,711***	*540,942*
Less: Current Maturities--net of Unamortized Debt Issuance Costs	***186***	*33,201*
Unamortized Long-Term Debt Issuance Costs	***2,145***	*2,400*
Total Consolidated Long-Term Debt net of Unamortized Debt Issuance Costs	***490,380***	*505,341*
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	***696,892***	*670,104*
Total Capitalization	**$*1,187,272***	$*1,175,445*

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation

Notes to Consolidated Financial Statements

For the years ended December 31, 2017, 2016 and 2015

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*).

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.

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 *$741,000* in *2017, $495,000* in *2016* and *$723,000* in *2015.* 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 *2.74%* in *2017, 2.88%* in *2016* and *2.61%* in *2015.* 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 (*3* 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 *2017, 2016* or *2015.* 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.

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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, 2017* and *2016* 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 Ownership Percentage	Electric Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Plant
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[1]	*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[1]	*50.0* %	*53,225*	--	*(434*)	*52,791*
Big Stone South–Ellendale 345 kV line[1]	*50.0* %	--	*89,980*	--	*89,980*
December 31, 2016					
Big Stone Plant	*53.9* %	$*328,809*	$ *23*	$ *(65,665*)	$*263,167*
Coyote Station	*35.0* %	*176,315*	*113*	*(101,499*)	*74,929*
Fargo-Monticello 345 kV line	*14.2* %	*78,298*	--	*(3,511*)	*74,787*
Brookings-Southeast Twin Cities 345 kV line[1]	*4.8* %	*26,406*	--	*(924*)	*25,482*
Bemidji-Grand Rapids 230 kV line	*14.8* %	*16,331*	--	*(1,573*)	*14,758*
Big Stone South–Brookings 345 kV line[1]	*50.0* %	--	*45,050*	--	*45,050*
Big Stone South–Ellendale 345 kV line[1]	*50.0* %	--	*49,160*	--	*49,160*

[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.

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, 2017* could be as high as *$57.1* 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 *13* 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 *13* to consolidated financial statements.

Revenue Recognition

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, the price is fixed or determinable and collectability is reasonably assured. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns are recorded at the time of the sale based on historical information and current trends.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies have *no* further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point. The majority of the revenues recorded by the companies in the Manufacturing and Plastics segments are recorded when products are shipped.

Customer electricity use is metered and bills are rendered monthly. Revenue is accrued for electricity consumed but *not* yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment, under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is recognized for fuel and purchased power costs incurred in excess of amounts recovered in base rates but *not* yet billed through the fuel clause adjustment, for conservation program incentives and bonuses earned but *not* yet billed and for renewable resource, transmission-related and environmental incurred costs and investment returns approved for recovery through riders.

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered. For shared use of transmission facilities with certain regional transmission cooperatives, revenues are estimated. Bills are rendered based on anticipated usage and settlements are made later based on actual usage. Estimated revenues *may* be adjusted prior to settlement, or at the time of settlement, to reflect actual usage.

Under ASC Topic *815, Derivatives and Hedging*, OTP accounts for forward energy contracts as derivatives subject to mark-to-market accounting unless those contracts meet the definition of a capacity contract or are *not* subject to unplanned netting, then OTP accounts for the contracts under the normal purchases and sales exception to mark-to-market accounting.

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.

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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)	2017	2016
Cost Method:		
Economic Development Loan Pools	$*45*	$*54*
Other	*115*	*115*
Equity Method Partnerships	*24*	*23*
Marketable Debt Securities Classified as Available-for-Sale	*7,160*	*8,225*
Marketable Equity Securities Classified as Available-for-Sale	*1,285*	--
Total Investments	$*8,629*	$*8,417*

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, 2017.* See further discussion below.

Agreements Subject to Legally Enforceable Netting Arrangements

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

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.

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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, 2017* and *December 31, 2016:*

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*	

December 31, 2016 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		$*5,280*	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		*2,945*	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	$*849*		
Total Assets	$*849*	$*8,225*	

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

Electric segment inventories are reported at average cost. The Manufacturing and Plastics segments' inventories are stated at the lower of average cost or market. Inventories consist of the following at *December 31:*

(in thousands)	2017	2016
Finished Goods	$*26,605*	$*27,755*
Work in Process	*14,222*	*11,754*
Raw Material, Fuel and Supplies	*47,207*	*44,231*
Total Inventories	$*88,034*	$*83,740*

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.

In the *first* quarter of *2015,* Foley recorded a *$1.0* million goodwill impairment charge based on adjustments to the carrying value of Foley. The *first* quarter *2015* goodwill impairment loss is reflected in the results of discontinued operations. See note *15* to consolidated financial statements.

On *September 1, 2015* BTD Manufacturing, Inc. (BTD), acquired the assets of Impulse Manufacturing, Inc. (Impulse) of Dawsonville, Georgia. The acquired business operates under the name BTD-Georgia. Based on the preliminary purchase price allocation, the difference in the fair value of assets acquired and the price paid for Impulse resulted in an initial estimate of acquired goodwill of *$8.2* million. A final determination of the purchase price was agreed to in *June 2016* resulting in a *$2.2* million reduction in acquired goodwill in *June 2016.*

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The following tables summarize changes to goodwill by business segment during *2017* and *2016:*

(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*

(in thousands)	Gross Balance December 31, 2015	Accumulated Impairments	Balance (net of impairments) December 31, 2015	Adjustments to Goodwill in 2016	Balance (net of impairments) December 31, 2016
Manufacturing	$ *20,430*	$ --	$ *20,430*	$ *(2,160*)	$ *18,270*
Plastics	*19,302*	--	*19,302*	--	*19,302*
Total	$ *39,732*	$ --	$ *39,732*	$ *(2,160*)	$ *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*. In *2017* the Company capitalized *$154,000* in implementation costs for new financial reporting consolidation software included in other amortizable intangible assets. In *September 2017* the Company initiated use of the software and began amortizing the implementation costs.

The following table summarizes the components of the Company's intangible assets at *December 31, 2017* and *December 31, 2016:*

December 31, 2017 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
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*			
December 31, 2016 *(in thousands)*						
Amortizable Intangible Assets:						
Customer Relationships	$ *22,491*	$ *7,861*	$ *14,630*	*36*	-	*224*
Covenant not to Compete	*590*	*262*	*328*		*20*	
Total	$ *23,081*	$ *8,123*	$ *14,958*			

The amortization expense for these intangible assets was:

(in thousands)	2017	2016	2015
Amortization Expense – Intangible Assets	$*1,347*	$*1,436*	$*1,127*

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

(in thousands)	2018	2019	2020	2021	2022
Estimated Amortization Expense – Intangible Assets	$*1,315*	$*1,184*	$*1,133*	$*1,099*	$*1,099*

Supplemental Disclosures of Cash Flow Information

	As of December 31,	
(in thousands)	2017	2016
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$*13,887*	$*13,533*

(in thousands)	2017	2016	2015
Cash Paid (Received) During the Year for:			
Interest (net of amount capitalized)	$*29,791*	$*31,269*	$*30,512*
Income Taxes	$*5,064*	$*(1,291*)	$*7,322*

New Accounting Standards Adopted

Accounting Standards Update (ASU) *2015-11*—In *July 2015* the Financial Accounting Standards Board (FASB) issued ASU *No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory,* which requires that inventories be measured at the lower of cost or net realizable value instead of the lower of cost or market value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The standards update was effective prospectively for fiscal years and interim periods beginning after *December 15, 2016.* The Company adopted the updates in ASU *2015-11* in the *first* quarter of *2017.* The adoption of the updated standard did *not* have a material impact on the Company's consolidated financial statements as market and net realizable value were substantially the same for the inventories of its manufacturing companies.

New Accounting Standards Pending Adoption

ASU *2014-09*—In *May 2014* the FASB issued ASU *No. 2014-09, Revenue from Contracts with Customers (Topic 606)* (ASC *606*). ASC *606* is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC *606* also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Amendments to the ASC in ASU *2014-09,* as amended, are effective for fiscal years beginning after *December 15, 2017.* Early adoption is permitted. Application methods permitted are: (*1*) full retrospective, (*2*) retrospective using *one* or more practical expedients and (*3*) retrospective with the cumulative effect of initial application recognized at the date of initial application. As of *December 31, 2017* the Company had reviewed its revenue streams and contracts and determined areas where the amendments in ASU *2014-09* are applicable and has developed controls for new processes that will be required to track and report revenues where the timing of revenue recognition *may* change under ASU *2014-09.* 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 ASU *2016-09.* The Company will adopt the updates in ASU *2014-09* on a modified retrospective basis on *January 1, 2018,* the date of initial application, but will *not* be recording a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASU *606* have *no* material impact on the timing of revenue recognition for the Company or its subsidiaries. Adoption of ASU *2014-09* will result in additional disclosures related to the nature, timing and certainty of revenues and any contract assets or liabilities that *may* be required to be reported under the updated standard.

The Company will report adjustments to Alternative Revenue Program (ARP) revenues at OTP as a separate line item within revenue on the face of the Company's consolidated statements of income. The ARP revenue adjustments are recorded on the basis of recoverable costs incurred and returns earned under rate riders and are *not* considered revenue from contracts with customers.

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

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

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

ASU *2017-07*—In *March 2017* the FASB issued ASU *No. 2017-07, Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU *2017-07*), which is intended to improve 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. 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 amendments in ASU *2017-07* also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of internally manufactured inventory or a self-constructed asset). The amendments in ASU *2017-07* are effective for annual periods beginning after *December 15, 2017,* including interim periods within those annual periods. The amendments will be 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 income statement 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, 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 of the components of net periodic pension costs as recoverable operating expenses. The Company has assessed the impact adoption of the amendments in ASU *2017-07* will have on its consolidated financial statements, financial position and results of operations and OTP has determined the regulatory assets to be established in order to reflect the effect of the required regulatory accounting treatment of the non-service cost components that cannot be capitalized to plant in service under the ASU *2017-07* amendments to GAAP. The non-service cost components of the affected net periodic benefit costs will be reported below the operating income line on the Company's consolidated income statements upon adoption of the amendments in ASU *2017-07.*

The Company does *not* plan to adopt the updates in ASU *2017-07* prior to the *first* quarter of *2018,* the required effective period for application of the updates by the Company. The Company's non-service cost components of net periodic post-retirement benefit costs that were capitalized to plant in service in *2017* that would have been recorded as regulatory assets if the amendments in ASU *2017-07* were applicable in *2017* were *$0.8* million. The Company's non-service costs components of net periodic postretirement benefit costs included in operating expense that will be included in other income and deductions on adoption of ASU *2017-07* were *$5.6* million in *2017* and *$5.1* million in *2016.*

2. Business Combinations, Dispositions and Segment Information

Business Combinations

The Company acquired *no* new businesses in *2017* or *2016.*

On *September 1, 2015* BTD acquired the assets of Impulse of Dawsonville, Georgia for *$30.8* million in cash. A post-closing reduction in the purchase price of *$1.5* million was agreed to in *June 2016* resulting in an adjusted purchase price of *$29.3* million. The acquired business, operating under the name BTD-Georgia, is a full-service metal fabricator located *30* miles north of Atlanta, Georgia, which 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. In addition to serving some of BTD's existing customers from a location closer to the customers' manufacturing facilities, this acquisition provides opportunities for growth in new and existing markets for BTD with complementing production capabilities that expand the capacity of services offered by BTD. Pro forma results of operations have *not* been presented for this acquisition because the effect of the acquisition was *not* material to the Company.

Below is condensed balance sheet information disclosing the final allocation of the purchase price assigned to each major asset and liability category of BTD-Georgia:

(in thousands)	
Assets:	
Current Assets	$*4,906*
Goodwill	*6,083*
Other Intangible Assets	*6,270*
Other Amortizable Assets	*1,380*
Fixed Assets	*13,649*
Total Assets	$*32,288*
Liabilities:	
Current Liabilities	$*2,971*
Lease Obligation	*11*
Total Liabilities	$*2,982*
Cash Paid	$*29,306*

In execution of the Company's announced strategy of realigning its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations, the Company sold several of its holdings in recent years. On *December 31, 2014* the Company was in the process of negotiating the sales of Foley, its mechanical and prime contractor on industrial projects, and AEV, Inc., its electrical design and construction services company, which resulted in the removal of its Construction segment from continuing operations. The sale of Foley closed on *April 30, 2015* and the sale of the assets of AEV, Inc. closed on *February 28, 2015.*

The results of operations of the Company's recently disposed businesses are reported as discontinued operations in the Company's consolidated financial statements as of and for the years ended *December 31, 2017, 2016* and *2015,* and are summarized in note *15* to consolidated financial statements.

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Segment Information

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

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

No single customer accounted for over *10%* of the Company's consolidated revenues in *2017, 2016* and *2015.* While *no* single customer accounted for over *10%* of consolidated revenue in *2017,* certain customers provided a significant portion of each business segment's *2017* revenue. The Electric segment has *one* customer that provided *11.7%* of *2017* Electric segment revenues. The Manufacturing segment has *one* customer that manufactures and sells recreational vehicles that provided *24.3%* of *2017* Manufacturing segment revenues and *one* customer that manufactures and sells lawn and garden equipment that provided *12.0%* of *2017* Manufacturing segment revenues. The Plastics segment has *two* customers that individually provided *20.6%* and *17.8%* of *2017* Plastics segment revenues. The loss of any *one* of these customers would have a significant negative impact on the financial position and results of operations of the respective business segment and the Company.

All of the Company’s long-lived assets are within the United States and sales within the United States accounted for *98.2%* of sales in *2017, 98.6%* of sales in *2016* and *97.1%* of sales in *2015.*

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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 on continuing operations for the business segments for *2017, 2016* and *2015* is presented in the following table:

(in thousands)	2017	2016	2015
Operating Revenue			
Electric	$*434,537*	$*427,383*	$*407,131*
Manufacturing	*229,738*	*221,289*	*215,011*
Plastics	*185,132*	*154,901*	*157,758*
Intersegment Eliminations	*(57*)	*(34*)	*(96*)
Total	$*849,350*	$*803,539*	$*779,804*
Cost of Products Sold			
Manufacturing	$*176,473*	$*171,732*	$*171,956*
Plastics	*140,107*	*123,496*	*123,085*
Intersegment Eliminations	*(18*)	*(6*)	*(9*)
Total	$*316,562*	$*295,222*	$*295,032*
Other Nonelectric Expenses			
Manufacturing	$*23,785*	$*21,994*	$*21,116*
Plastics	*11,564*	*9,402*	*9,849*
Corporate	*7,930*	*8,896*	*9,143*
Intersegment Eliminations	*(39*)	*(28*)	*(87*)
Total	$*43,240*	$*40,264*	$*40,021*
Depreciation and Amortization			
Electric	$*53,276*	$*53,743*	$*44,786*
Manufacturing	*15,379*	*15,794*	*11,853*
Plastics	*3,817*	*3,861*	*3,552*
Corporate	*73*	*47*	*172*
Total	$*72,545*	$*73,445*	$*60,363*
Operating Income (Loss)			
Electric	$*90,392*	$*90,131*	$*87,171*
Manufacturing	*14,101*	*11,769*	*10,086*
Plastics	*29,644*	*18,142*	*21,272*
Corporate	*(8,003*)	*(8,943*)	*(9,315*)
Total	$*126,134*	$*111,099*	$*109,214*
Interest Charges			
Electric	$*25,334*	$*25,069*	$*24,371*
Manufacturing	*2,215*	*3,859*	*3,560*
Plastics	*633*	*1,034*	*1,026*
Corporate and Intersegment Eliminations	*1,422*	*1,924*	*2,203*
Total	$*29,604*	$*31,886*	$*31,160*
Income Tax Expense (Benefit) – Continuing Operations			
Electric	$*17,013*	$*16,366*	$*16,067*
Manufacturing	*989*	*2,276*	*2,299*
Plastics	*7,448*	*6,538*	*8,187*
Corporate	*1,593*	*(5,099*)	*(4,911*)
Total	$*27,043*	$*20,081*	$*21,642*

Net Income (Loss)			
Electric	$*49,446*	$*49,829*	$*48,370*
Manufacturing	*11,050*	*5,694*	*4,247*
Plastics	*21,696*	*10,628*	*12,108*
Corporate	*(10,073*)	*(4,114*)	*(6,136*)
Discontinued Operations	*320*	*284*	*756*
Total	$*72,439*	$*62,321*	$*59,345*

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(in thousands)	2017	2016	2015
Capital Expenditures			
Electric	$*118,444*	$*149,648*	$*135,572*
Manufacturing	*9,916*	*8,429*	*20,295*
Plastics	*4,432*	*3,085*	*4,206*
Corporate	*121*	*97*	*11*
Total	$*132,913*	$*161,259*	$*160,084*
Identifiable Assets			
Electric	$*1,690,224*	$*1,622,231*	$*1,520,887*
Manufacturing	*167,023*	*166,525*	*173,860*
Plastics	*87,230*	*84,592*	*81,624*
Corporate	*59,801*	*39,037*	*42,312*
Total	$*2,004,278*	$*1,912,385*	$*1,818,683*

3. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP's revenues in *2017, 2016* and *2015.*

Major Capital Expenditure Projects

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a *345*-kiloVolt (kV) transmission line that will extend *163* miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in *December 2011.* MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the *second* quarter of *2016* and is expected to be completed in *2019.* OTP's capitalized costs on this project as of *December 31, 2017* were approximately *$90.0* million, which includes assets that are *100%* owned by OTP.

Big Stone South–Brookings MVP—This *345*-kV transmission line extends approximately *70* miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and

Northern States Power–Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in *December 2011.* Construction began on this line in the *third* quarter of *2015* and the line was energized on *September 8, 2017.* OTP's capitalized costs on this project as of *December 31, 2017* were approximately *$72.7* million, which includes assets that are *100%* owned by OTP.

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

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 AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) were initially incurred in *2015* when projects went into service.

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Minnesota

2016 General Rate Case—The MPUC rendered its final decision in OTP's *2016* general rate case in *March 2017* and issued its written order on *May 1, 2017*. Pursuant to the order, OTP's allowed rate of return on rate base decreased from *8.61%* to *7.5056%* and its allowed rate of return on equity decreased from *10.74%* to *9.41%*. On *July 6, 2017* the MPUC denied OTP's request for reconsideration of certain of the MPUC's rulings in the rate case and confirmed its *May 1, 2017* order.

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 MVP projects will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers, and (*2*) approval of OTP's proposal to transition rate base, expenses and revenues from Environmental Cost Recovery (ECR) and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates will be used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

Information on interim and final rate increases and interim revenue refunds accrued is detailed in the tables below:

($ in thousands)	Interim Rates Authorized April 14, 2016	Final Rates
Revenue Increase – Annualized based on Test Year Data	$ *16,816*	$ *10,471*
Revenue Percent Increase	*9.56* %	*5.34* %
Return on Rate Base	*8.07* %	*7.5056* %
Jurisdictional Rate Base based on Test Year Data	$ *483,000*	$ *471,000*
Return on Equity	*10.40* %	*9.41* %
Based on Equity to Total Capital of	*52.50* %	*52.50* %
Debt to Total Capital	*47.50* %	*47.50* %

Interim Revenue *(in thousands)*	April 16, 2016 through October 31, 2017
Billed	$ *23,289*
Accrued Refund	$ *8,779*
Net Interim Revenue	$ *14,510*
Interest on Refundable Amount	$ *265*

Final Refund	$ *9,044*

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

OTP accrued interim and rider rate refunds until final rates became effective, for bills rendered on and after *November 1, 2017.* 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.*

<u>Minnesota Conservation Improvement Programs (MNCIP)</u>—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 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.

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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. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately *50%* compared to the previous incentive mechanism. MNCIP incentives included *$5.0* million approved for *2016* and *$4.3* million approved for *2015.*

Based on results from the *2017* MNCIP program year, OTP recognized a financial incentive of *$2.6* million in *2017.* The *2017* program resulted in an approximate *10%* decrease in energy savings compared to *2016* program results. OTP will request approval for recovery of its *2017* MNCIP program costs *not* included in base rates, a *$2.6* million financial incentive and an update to the MNCIP surcharge from the MPUC by *April 1, 2018.*

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) provides 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 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 last general rate case. Additionally, following approval of the 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 MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment will result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the *two* jurisdictions at any given time. On *August 18, 2017* OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to allocate costs between jurisdictions of the FERC MVP transmission projects in the TCR rider. OTP believes the

MPUC-ordered treatment conflicts with federal authority over transmission of electricity in interstate commerce and rates for the transmission of electricity subject to the jurisdiction of the FERC as set forth in the Federal Power Act of *1935,* as amended (Federal Power Act). A decision is expected in late *2018.*

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

Reagent Costs and Emission Allowances—On *July 31, 2014* OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On *March 12, 2015* the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs were included in OTP's *2016* general rate case in Minnesota and were considered for recovery either through the FCA rider or general rates. In its *2016* general rate case order issued *May 1, 2017* the MPUC again denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs or through the FCA rider. Instead, the test-year costs will be recovered in general rates and variability of those costs in excess of amounts included in general rates will only be recovered to the extent actual kilowatt-hour (kwh) sales exceed forecasted kwh sales used to establish general 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%.* In the request, OTP proposed an allowed return on rate base of *7.97%* and an allowed rate of return on equity of *10.30%.* On *December 20, 2017* the NDPSC approved OTP's request for interim rates to increase annual revenue collections by *$12.8* million, effective *January 1, 2018.* OTP used a lower rate of return on equity in the calculation of interim rates based on the rate of return on equity used in its *2018* test-year rate request.

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

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

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

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

South Dakota

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately *$643,000* or approximately *2.32%* was granted by the SDPUC in an order issued on *April 21, 2011* and effective with bills rendered on and after *June 1, 2011.* Pursuant to the order, OTP's allowed rate of return on rate base was set at *8.50%.*

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

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

Reagent Costs and Emission Allowances—On *August 1, 2014* OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On *September 16, 2014* the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

TCJA

The TCJA reduced the federal corporate income tax rate from *35%* to *21%.* Currently, all OTP rates have been developed using a *35%* tax rate. The MPUC, the NDPSC, the SDPUC and the FERC have all initiated dockets or proceedings to begin working with utilities to assess the impact of the lower income tax rates under the TCJA on electric rates, and develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required its regulated utilities to make filings by *January 30, 2018* and *February 15, 2018,* but has *not* made a determination on rate treatment. OTP currently has an active rate case in North Dakota and anticipates incorporating the impact of the tax changes to North Dakota rates within that proceeding. The SDPUC required initial comments by *February 1, 2018* and indicated that revenues collected subsequent to *December 31, 2017* would be subject to refund, pending determination of the impacts of the TCJA. OTP is still assessing these impacts and will continue to work with the respective commissions to determine if any rate adjustments are necessary, and if so, to determine the appropriate timing and approach for making those adjustments.

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Rate Rider Updates

The following table provides summary information on the status of updates since *January 1, 2014* 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				
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
2013 Incentive and Cost Recovery	A – September 26, 2014	October 1, 2014	$ *8,862*	$0.00263/kwh
Transmission Cost Recovery				
2017 Rate Reset[1]	A – October 30, 2017	November 1, 2017	$ *(3,311)*	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	$ *4,736*	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	$ *7,203*	Various
2014 Annual Update	A – February 18, 2015	March 1, 2015	$ *8,388*	Various
2013 Annual Update	A – June 24, 2014	March 1, 2014	$ *2,066*	Various
Environmental Cost Recovery				
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$ *(1,943)*	-0.935% of base
2016 Annual Update	A – July 5, 2016	September 1, 2016	$ *11,884*	6.927% of base
2015 Annual Update	A – March 9, 2016	October 1, 2015	$ *12,104*	7.006% of base
2014 Annual Update	A – November 26, 2014	December 1, 2014	*$ 9,229* [2]	7.006% of base
North Dakota				
Renewable Resource Adjustment				
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
2013 Annual Update	A – March 12, 2014	April 1, 2014	$ *8,068*	$0.00437/kwh
Transmission Cost Recovery				
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
2014 Annual Update	A – December 17, 2014	January 1, 2015	$ *8,463*	Various
Environmental Cost Recovery				
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$ *8,537*	6.629% of base
2017 Annual Update	A – July 12, 2017	August 1, 2017	$ *9,917*	7.633% of base
2016 Annual Update	A – June 22, 2016	July 1, 2016	$ *10,359*	7.904% of base
2015 Annual Update	A – June 17, 2015	July 1, 2015	$ *12,249*	9.193% of base

2014 Annual Update	A – July 10, 2014	August 1, 2014	$ *9,880*	7.531% of base
South Dakota				
Transmission Cost Recovery				
2017 Annual Update	R – November 1, 2017	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
2013 Annual Update	A – February 18, 2014	March 1, 2014	$ *1,349*	Various
Environmental Cost Recovery				
2017 Annual Update	A – October 13, 2017	November 1, 2017	$ *2,082*	$0.00483/kwh
2016 Annual Update	A – October 26, 2016	November 1, 2016	$ *2,238*	$0.00536/kwh
2015 Annual Update	A – October 15, 2015	November 1, 2015	$ *2,728*	$0.00643/kwh
2014 Initial Request	A – November 25, 2014	December 1, 2014	$ *1,995*	$0.00487/kwh

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

[2]*Amount approved for recovery over ten months through September 30, 2015. Initial 2014 annual update requirement was $10.2 million to be effective October 1, 2014. Due to delayed approval, the amount was reduced for revenues billed under the rider rate in effect from October 1, 2014 through November 30, 2014.*

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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)*	2017	2016	2015
Minnesota			
Conservation Improvement Program Costs and Incentives[1]	$ *9,225*	$ *12,920*	$ *10,724*
Transmission Cost Recovery	*2,973*	*5,795*	*5,202*
Environmental Cost Recovery	*8,148*	*12,443*	*10,238*
North Dakota			
Renewable Resource Adjustment	*7,620*	*7,800*	*8,409*
Transmission Cost Recovery	*8,729*	*7,694*	*6,609*
Environmental Cost Recovery	*9,782*	*11,089*	*9,502*
South Dakota			
Transmission Cost Recovery	*1,843*	*1,820*	*1,290*
Environmental Cost Recovery	*2,345*	*2,538*	*1,967*
Conservation Improvement Program Costs and Incentives	*598*	*468*	*583*

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

FERC

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

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

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

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

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

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

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

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, 2017			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]	$*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*
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	--	*1,985*	*1,985*	*24*
Debt Reacquisition Premiums[1]	*254*	*960*	*1,214*	*177*
Big Stone II Unrecovered Project Costs – South Dakota[1]	*100*	*442*	*542*	*65*
North Dakota Renewable Resource Rider Accrued Revenues[2]	*206*	*236*	*442*	*15*

North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	*309*	--	*309*	*12*
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	*267*	--	*267*	*4*
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	*152*	--	*152*	*12*
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[2]	*75*	--	*75*	*12*
Total Regulatory Assets	$*22,551*	$*129,576*	$*152,127*	
Regulatory Liabilities:				
Deferred Income Taxes	$--	$*149,052*	$*149,052*	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	*83,100*	*83,100*	asset lives
Refundable Fuel Clause Adjustment Revenues	*5,778*	--	*5,778*	*12*
Minnesota Environmental Cost Recovery Rider Accrued Refund	*1,667*	--	*1,667*	*11*
Minnesota Transmission Cost Recovery Rider Accrued Refund	*802*	*609*	*1,411*	*22*
Minnesota Renewable Resource Recovery Rider Accrued Refund	*409*	--	*409*	*12*
North Dakota Transmission Cost Recovery Rider Accrued Refund	*349*	--	*349*	*12*
Revenue for Rate Case Expenses Subject to Refund – Minnesota	*208*	--	*208*	*4*
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*
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.*

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(in thousands)	December 31, 2016 Current	Long-Term	Total	Remaining Recovery/ Refund Period (months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$*6,443*	$ *108,267*	$*114,710*	see below
Conservation Improvement Program Costs and Incentives[2]	*4,836*	*5,158*	*9,994*	*21*
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	*6,153*	*6,153*	asset lives
Deferred Marked-to-Market Losses[1]	*4,063*	*6,467*	*10,530*	*48*
Big Stone II Unrecovered Project Costs – Minnesota[1]	*778*	*2,087*	*2,865*	*52*
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	*333*	--	*333*	*12*
Debt Reacquisition Premiums[1]	*325*	*1,214*	*1,539*	*189*
Big Stone II Unrecovered Project Costs – South Dakota[2]	*100*	*543*	*643*	*77*
North Dakota Renewable Resource Rider Accrued Revenues[2]	*1,319*	*482*	*1,801*	*15*
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	*1,082*	--	*1,082*	*12*
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	*113*	--	*113*	*12*
Deferred Income Taxes[1]	--	*1,014*	*1,014*	asset lives
Recoverable Fuel and Purchased Power Costs[1]	*1,798*	--	*1,798*	*12*
Minnesota Renewable Resource Rider Accrued Revenues[2]	*34*	--	*34*	*9*
North Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	--	*568*	*568*	*24*
South Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	*73*	*141*	*214*	*14*
Total Regulatory Assets	$*21,297*	$ *132,094*	$*153,391*	
Regulatory Liabilities:				
Deferred Income Taxes	$--	$ *818*	$*818*	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	*80,404*	*80,404*	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	*139*	--	*139*	*12*
Minnesota Transmission Cost Recovery Rider Accrued Refund	*757*			