

Otter Tail Corp
Form 10-K
March 03, 2014

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

FORM 10-K
(Mark One)

- ☒ Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2013
- ☐ Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the transition period from _____ to _____

Commission File Number 0-53713

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

MINNESOTA
(State or other jurisdiction of incorporation or organization)

27-0383995
(I.R.S. Employer Identification No.)

215 SOUTH CASCADE STREET, BOX 496, FERGUS
FALLS, MINNESOTA
(Address of principal executive offices)

56538-0496
(Zip Code)

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

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

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

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

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

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 o No x)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. (Yes x No o)

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

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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" and "smaller reporting 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)

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 28, 2013 was \$972,636,461.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 36,340,637 Common Shares (\$5 par value) as of February 14, 2014.

Documents Incorporated by Reference:

Proxy Statement for the 2014 Annual Meeting-Portions incorporated by reference into Part III

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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
Aevenia	Aevenia, Inc.
AFUDC	Allowance for Funds Used During Construction
AQCS	Air Quality Control System
ARO	Accumulated Asset Retirement Obligation
ASC	Accounting Standards Codification
ASC 980	ASC Topic 980 - Regulated Operations
ASM	Ancillary Services Market
Aviva	Aviva Sports, Inc.
BACT	Best-Available Control Technology
BART	Best-Available Retrofit Technology
Bemidji Project	Bemidji-Grand Rapids 230 kV Project
Brookings Project	Brookings-Southeast Twin Cities 345 kV Project
BTD	BTD Manufacturing, Inc.
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CapX2020	Capacity Expansion 2020
Cascade	Cascade Investment LLC
Cascade Note	\$50 million 8.89% Senior Unsecured Note due November 30, 2017
CCMC	Coyote Creek Mining Company, L.L.C.
CO2	Carbon Dioxide
CON	Certificate of Need
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction Work in Progress
DENR	Department of Environment and Natural Resources
DMS	DMS Health Technologies, Inc.
ECR	Environmental Cost Recovery
EEI	Edison Electric Institute Index
EEP	Energy Efficiency Plan
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESSRP	Executive Survivor and Supplemental Retirement Plan
Fargo Project	Fargo-Monticello 345 kV Project
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Foley	Foley Company
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
IMD	IMD, Inc.
IPH	Idaho Pacific Holdings, Inc.
IRP	Integrated Resource Plan

JPMS	J.P. Morgan Securities
kV	kiloVolt
kW	kiloWatt
kwh	kilowatt-hour
LSA	Lignite Sales Agreement
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards
MDU	MDU Resources Group, Inc.
MEI	Moorhead Electric, Inc.
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

MNRRRA	Minnesota Renewable Resource Adjustment
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MRO	Midwest Reliability Organization
MVP	Multi-Value Project
MW	Megawatt
mwh	Megawatt-hour
NAEMA	North American Energy Marketers Association
NDDOH	North Dakota Department of Health
NDPSC	North Dakota Public Service Commission
NDRRA	North Dakota Renewable Resource Adjustment
NICF	Notice of Intent to Construct Facilities
NPCA	National Parks Conservation Association
NPDES	National Pollutant Discharge Elimination System
Northern Pipe	Northern Pipe Products, Inc.
NOx	Nitrogen Oxide
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
OTESCO	Otter Tail Energy Services Company
OTP	Otter Tail Power Company
PCOR	Plains CO2 Reduction Partnership
PEM	Power and Energy Market
PM2.5	Particulate Matter Less Than 2.5 Microns
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PVC	Polyvinyl Chloride
RCRA	Resource Conservation and Recovery Act
SCR	Selective Catalytic Reduction
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
SF6	Sulfur Hexafluoride
Shrco	Shrco, Inc.
SIP	State Implementation Plan
SO2	Sulfur Dioxide
T.O. Plastics	T.O. Plastics, Inc.
Tariff	Energy and Operating Reserve Markets Tariff
TCR	Transmission Cost Recovery
Trinity	Trinity Industries, Inc.
Varistar	Varistar Corporation
VIC	Voluntary Investigation and Cleanup
VIE	Variable Interest Entity
Vinyltech	Vinyltech Corporation
Wylie	E.W. Wylie Corporation

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 electric and nonelectric 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 internet 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 2,336 full-time employees in its continuing operations at December 31, 2013. The Company’s businesses have been classified in four segments to be consistent with its business strategy and the reporting and review process used by the Company’s chief operating decision maker. The four segments are Electric, Manufacturing, Plastics and Construction. We may refer to our Manufacturing, Plastics and Construction segments collectively as our manufacturing and infrastructure businesses.

Over the last three years, the Company sold several businesses in execution of an announced strategy to realign its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations. In 2011, the Company sold Idaho Pacific Holdings, Inc. (IPH), its Food Ingredient Processing business, and E.W. Wylie Corporation (Wylie), its trucking company, which was included in its former Wind Energy segment. In January 2012, the Company sold the assets of Aviva Sports, Inc. (Aviva), a recreational equipment manufacturer and a wholly owned subsidiary of Shrco, Inc. (Shrco), the Company’s former waterfront equipment manufacturer. In February 2012, the Company sold DMS Health Technologies, Inc. (DMS), its former Health Services segment business. In November 2012, the Company completed the sale of the assets of IMD, Inc. (IMD), the Company’s former wind tower manufacturer, and exited the wind tower manufacturing business. On February 8, 2013 the Company sold substantially all the assets of Shrco.

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 an active wholesale participant in the Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907. Additionally, the electric segment includes Otter Tail Energy Services Company (OTESCO), which provided technical and engineering services through December 31, 2012. OTESCO ceased operations and did not record any operating revenues, expenses or net income in 2013.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping and fabrication, and production of material and handling trays and horticultural containers. These businesses have manufacturing facilities in 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.

Construction consists of businesses involved in commercial and industrial electric contracting and construction of fiber optic, electric distribution, water, wastewater and HVAC systems primarily in the central United States.

OTP is a wholly owned subsidiary of the Company. All of the Company's manufacturing and infrastructure 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.

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 2012 as the measurement year. 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 already in place at the Company's manufacturing and infrastructure businesses. The Company will continue to review its business portfolio to see where additional opportunities exist to improve its risk profile, improve credit metrics and generate additional sources of cash to support the growth opportunities in its electric utility. The Company will also evaluate opportunities to allocate capital to potential acquisitions in its Manufacturing segment. 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 infrastructure 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 2013 was 77% from the electric utility and 23% from the manufacturing and infrastructure businesses.

In evaluating its portfolio of operating companies, the Company looks for the following characteristics:

a threshold level of net earnings and a return on invested capital in excess of the Company's weighted average cost of capital,

a strategic differentiation from competitors and a sustainable cost advantage,

a stable or growing industry,

an ability to quickly adapt to changing economic cycles, and
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 38 through 65 of this Annual Report on Form 10-K.

(b) Financial Information about Industry Segments

The Company is engaged in businesses classified into four segments: Electric, Manufacturing, Plastics and Construction. Financial information about the Company's segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 85 through 87 of this Annual Report on Form 10-K.

(c) Narrative Description of Business

ELECTRIC

General

Electric includes OTP and, through December 31, 2012, the operations of OTESCO, which were not materially significant in 2012 and 2011. OTP, headquartered in Fergus Falls, Minnesota, provides electricity to more than 130,000 customers in a service area with outer boundaries that encompass a total expanse of 70,000 square miles of western Minnesota, eastern North Dakota, and northeastern South Dakota. OTESCO, headquartered in Fergus Falls, Minnesota, provided technical and engineering services primarily in North Dakota and Minnesota. The Company derived 42%, 41% and 41% of its consolidated operating revenues and 64%, 74% and 88% of its consolidated operating income from the Electric segment for the years ended December 31, 2013, 2012 and 2011, respectively.

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

State	2013	2012
Minnesota	48.2 %	48.9 %
North Dakota	42.8	42.0
South Dakota	9.0	9.1
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 125,646 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, 2013, OTP served 130,188 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant.

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

Customer Category	2013	2012
Commercial	36.9 %	36.0 %
Residential	33.3	32.6
Industrial	23.2	25.0
All Other Sources	6.6	6.4
Total	100.0 %	100.0 %

Wholesale electric energy kilowatt-hour (kwh) sales were 12.5% of total kwh sales for 2013 and 11.8% for 2012. Wholesale electric energy kwh sales increased by 13.9% between the years while revenue per kwh sold increased by 18.8%. Activity in the short-term energy market is subject to change based on a number of factors and it is difficult to predict the quantity of wholesale power sales or prices for wholesale power in the future.

Capacity and Demand

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As of December 31, 2013 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants	
Big Stone Plant	256,700kW
Coyote Station	149,000
Hoot Lake Plant	148,900
Total Baseload Net Plant	554,600kW
Combustion Turbine and Small Diesel Units	104,900kW
Hydroelectric Facilities	2,600kW
Owned Wind Facilities (rated at nameplate)	
Luverne Wind Farm (33 turbines)	49,500kW
Ashtabula Wind Center (32 turbines)	48,000
Langdon Wind Center (27 turbines)	40,500
Total Owned Wind Facilities	138,000kW

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 2013, OTP generated about 70.8% of its retail kwh sales and purchased the balance.

In addition to the owned facilities described above OTP had the following purchased power agreements in place on December 31, 2013:

Purchased Wind Power Agreements (rated at nameplate and greater than 2,000 kW)	
Ashtabula Wind III	62,400kW
Edgeley	21,000
Langdon	19,500
Total Purchased Wind	102,900kW
Other Purchased Power Agreements (in excess of 1 year and 500 kW)	
Great River Energy1	100,000kW
1 Through 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. The MISO Resource Adequacy Construct changed significantly for the 2013/2014 MISO Planning Year effective June 1, 2013. OTP met its MISO obligation for 2013. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2014 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 2013 and 2012:

Sources	2013		% of	2012		
	Net Kilowatt	Total		Net Kilowatt	% of Total	
	Hours	Kilowatt		Hours	Kilowatt	
	Generated	Hours		Generated	Hours	
	(Thousands)	Generated		(Thousands)	Generated	
Subbituminous Coal	2,322,608	62.4	%	2,094,293	61.2	%
Lignite Coal	881,973	23.7		782,358	22.9	
Wind and Hydro	471,176	12.7		490,387	14.3	
Natural Gas and Oil	43,165	1.2		55,637	1.6	

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Total	3,718,922	100.0	%	3,422,675	100.0	%
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OTP has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Peabody COALSALES, LLC	Wyoming subbituminous	December 31, 2016
Big Stone Plant	Westmoreland Resources, Inc.	Montana subbituminous	December 31, 2014
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	May 4, 2016
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, 2015

OTP has about 58% of its coal needs for Big Stone under contract through December 2016.

The contract with Dakota Westmoreland Corporation expires on May 4, 2016. 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 to be paid by the Coyote Station owners under the LSA will reflect 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 has about 84% of its anticipated coal needs for Hoot Lake Plant secured under contract through December 2015.

It is OTP's practice to maintain a minimum 30-day inventory (at full output) of coal at the Big Stone Plant and a 20-day inventory at Coyote Station and Hoot Lake Plant.

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 methodology to assess a 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 due to its location next to a coal mine.

The average cost of fuel consumed (including handling charges to the plant sites) per million British Thermal Units for the years 2013, 2012, and 2011 was \$2.055, \$2.108, and \$1.922, 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 is as follows:

Rates	Regulation	2013				2012			
		% of		% of		% of		% of	
		Electric		Revenues	% of kwh Sales	Electric		Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	43.8	%	42.5	%	45.2	%	43.4	%
ND Retail Sales	ND Public Service Commission	39.0		36.8		38.8		36.4	
SD Retail Sales	SD Public Utilities Commission	8.2		8.2		8.4		8.5	
Transmission & Wholesale	Federal Energy Regulatory Commission	9.0		12.5		7.6		11.7	
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 that 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 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.

The following summarizes 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 Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC. The Company's manufacturing and infrastructure businesses are not subject to direct regulation by any of these agencies.

Minnesota

Under the Minnesota Public Utilities 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 kilovolt (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.

2010 General Rate Case—OTP filed a general rate case on April 2, 2010 requesting an 8.01% base rate increase as well as a 3.8% interim rate increase. On May 27, 2010, the MPUC issued an order accepting the filing, suspending rates, and approving the interim rate increase, as requested, to be effective with customer usage on and after June 1, 2010. The MPUC held a hearing to decide on the issues in the rate case on March 25, 2011 and issued a written order on April 25, 2011. The MPUC authorized a revenue increase of approximately \$5.0 million, or 3.76% in base rate revenues, excluding the effect of moving recovery of wind investments to base rates. The MPUC's written order included: (1) recovery of Big Stone II costs over five years, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment. Final rates went into effect October 1, 2011. The overall increase to customers was approximately 1.6% compared to the authorized interim rate increase of 3.8%, which resulted in an interim rate refund to Minnesota retail electric customers of approximately \$3.9 million in the fourth quarter of 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%. OTP's authorized rates of return are based on a capital structure of 48.28% long term debt and 51.72% common equity.

Conservation Improvement Programs—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 Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal.

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 January 11, 2012 the MPUC approved the recovery of \$3.5 million for 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment increased from 3.0% to 3.8% for all Minnesota retail electric customers. On March 30, 2012 OTP recognized an additional \$0.4 million of incentive related to 2011 and submitted its annual 2011 financial incentive filing request for \$2.6 million. In December 2012, the MPUC approved the recovery of \$2.6 million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer's bill to an amount per kwh consumed. On January 1, 2013 OTP's MNCIP surcharge decreased from 3.8% of the customer's bill to \$0.00142 per kwh, which equates to approximately 1.9% of a customer's bill. OTP recognized \$2.6 million of MNCIP financial incentives in 2012 and an additional \$0.1 million in 2013 relating to 2012 program results. On October 10, 2013 the MPUC approved OTP's 2012 financial incentive request for \$2.7 million as well as its request for an updated surcharge rate to be implemented on November 1, 2013.

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.

In the MPUC order approving the 2011-2025 IRP in February 2012, OTP was required to submit a base-load diversification study specifically focused on evaluating retirement and repower options for the Hoot Lake Plant. In an order dated March 25, 2013 the MPUC approved OTP's recommendations that Hoot Lake Plant add pollution-control equipment at a cost of approximately \$10.0 million to comply with U.S. Environmental Protection Agency's (EPA) mercury and air toxics standards by 2015 and discontinue burning coal in 2020.

On December 2, 2013 OTP filed its 2014-2028 IRP with the MPUC. Copies of the 2014-2028 IRP were provided to both the NDPSC and SDPUC. Approximately 65% of the resource options called for by the 2014-2028 IRP are comprised of existing resources and wholesale energy purchases similar to existing levels. The remaining 35% is comprised of the following components: 65% natural gas simple cycle combustion turbines and 35% conservation and demand response. Capacity additions proposed in the 2014-2028 IRP are as follows:

Resource	Proposed Megawatts
Natural gas	194
Demand Response/Conservation	106

OTP expects a MPUC order on its 2014-2028 IRP filing during the second quarter of 2014.

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 integrated resource plan, 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 and coal and nuclear ranked fifth, the lowest ranking. The MPUC's current estimate of the range of costs of future CO2 regulation to be used in modeling analyses for resource plans is \$9

to \$34/ton of CO2 commencing in 2017. The MPUC is required to annually update these estimates.

Minnesota has a renewable energy standard which requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 17% by 2016; 20% by 2020 and 25% by 2025. In addition, a new standard established by the 2013 legislature requires 1.5% of total electric sales to be supplied by solar energy by the year 2020. OTP is currently evaluating the new legislation and potential options for meeting that standard. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. 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.

The costs for three major wind farms previously approved by the MPUC for recovery through OTP's Minnesota Renewable Resource Adjustment (MNRRA) were moved to base rates as of October 1, 2011 under the MPUC's April 25, 2011 general rate case order with the exception of the remaining balance of the MNRRA regulatory asset. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. Because the request to extend the period of the new rate for 18 months was still under review, a supplemental filing was submitted on February 15, 2013, requesting that the current rate be retained until a majority of the remaining costs were recovered and that the MNRRA rate be set to zero effective May 1, 2013. The MPUC approved the February 15, 2013 request on April 4, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case. Effective May 1, 2013 the resource adjustment on OTP's Minnesota customers' bills no longer includes MNRRA costs.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act provides a similar 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 2013 legislature passed legislation that 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. 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. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

OTP requested recovery of its transmission investments being recovered through its Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs then being recovered through OTP's Minnesota TCR rider to recovery in base rates. Final rates went into effect on October 1, 2011. OTP continues to utilize the TCR rider cost recovery mechanism to recover the remaining balance of current transmission projects and to recover costs associated with new transmission projects determined eligible for TCR rider recovery by the MPUC.

OTP filed a request for an update to its Minnesota TCR rider on October 5, 2010. In this TCR rider update, the MPUC addressed how to handle utility investments in transmission facilities that qualify for regional cost allocation under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from the other MISO utilities. On

March 26, 2012 the MPUC approved the update to OTP's Minnesota TCR rider along with an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made with an offsetting credit for revenues received from other MISO utilities under the MISO Tariff for projects included in the TCR. OTP's updated Minnesota TCR rider went into effect April 1, 2012.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On February 20, 2013 the MPUC approved three of the additional projects as eligible for recovery through the TCR rider. OTP filed its annual update to the TCR rider on February 7, 2013 to include the three new projects as well as updated costs associated with existing projects. On January 30, 2014 the MPUC approved OTP's 2013 TCR rider update but disallowed TCR rider recovery of capitalized internal labor costs and costs in excess of CON estimates. These costs will be removed from OTP's Minnesota TCR rider effective as of the date of the MPUC's order. OTP will be allowed to seek recovery of these costs in a future rate case.

Big Stone Air Quality Control System (AQCS)—Minnesota law authorizes a public utility to petition the MPUC for an Advance Determination of Prudence (ADP) for a project undertaken to comply with federal or state air quality standards of states in which the utility's electric generation facilities are located if the project has an expected jurisdictional cost to Minnesota ratepayers of at least \$10 million. On January 14, 2011 OTP filed a petition asking the MPUC for ADP for costs associated with the design, construction and operation of the Best-Available Retrofit Technology (BART) compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers. The MPUC granted OTP's petition for ADP for the AQCS in a written order issued on January 23, 2012. OTP's share of the costs for the Big Stone Plant AQCS is expected to be \$218 million.

On May 24, 2013 legislation was enacted in Minnesota which allowed OTP to file for an emission-reduction rider for recovery of the revenue requirements of the AQCS. The legislation authorizes the rider to allow a current return on investment (including Construction Work in Progress (CWIP)) at the level approved in OTP's most recent general rate case, unless a different return is determined by the MPUC to be in the public interest. On July 31, 2013 OTP filed for a Minnesota Environmental Cost Recovery (ECR) rider with the MPUC for recovery of its Minnesota jurisdictional share of the revenue requirements of its investment in the AQCS under construction at Big Stone Plant. The ECR rider recoverable revenue requirements include a current return on the project's CWIP balance. The MPUC granted approval of OTP's Minnesota ECR rider on December 18, 2013 with an effective date of January 1, 2014. The rate will be updated in an annual filing with the MPUC until the costs are rolled into base rates at an undetermined future date.

Big Stone II Project—OTP and a coalition of six other electric providers filed an application for a CON for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. On January 15, 2009 the MPUC approved a motion to grant the CON and Route Permit for the Minnesota portion of the Big Stone II transmission line project.

The MPUC granted the CON subject to a number of additional conditions, including but not limited to: (1) fulfilling various requirements relating to renewable energy goals, energy efficiency, community-based energy development projects and emissions reduction; (2) that the generation plant be built as a "carbon capture retrofit ready" facility; (3) that the applicants report to the MPUC on the feasibility of building the plant using ultra-supercritical technology; and (4) that the applicants achieve specific limits on construction costs at \$3,000/kW and CO₂ costs at \$26/ton.

The CON and Route Permit, required by state law, would have allowed the Big Stone II utilities to construct and upgrade 112 miles of electric transmission lines in western Minnesota for delivery of power from the Big Stone site and from numerous other planned generation projects, most of which are wind energy.

Following OTP's September 11, 2009 withdrawal from the Big Stone II project and the remaining Big Stone II participants' November 2, 2009 cancellation of the project, the suitability of the route permits and easements obtained by OTP as a MISO transmission owner for other interconnection customers backfilling through the MISO interconnection process into the Big Stone area continued to be evaluated. OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period which began on October 1, 2011. The amount of Big Stone II generation costs incurred by OTP that were deemed recoverable from Minnesota ratepayers as part of rates established in that proceeding was \$3.2 million (which excluded \$3.2 million of transmission-related project costs).

Approximately \$0.4 million of the total Minnesota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings Multi-Value Project (MVP) in the first quarter of 2013. The remaining costs, along with accumulated AFUDC, were transferred from CWIP to the Big Stone II Unrecovered Project Costs – Minnesota regulatory asset account in May 2013, based on recovery granted in the April 25, 2011 order. The recoverable amount of approximately \$3.5 million is expected to be recovered over an anticipated 89-month recovery period which began in May 2013.

Capacity Expansion 2020 (CapX2020)—CapX2020 is a joint initiative of eleven investor-owned, cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo–Monticello 345 kV Project (the Fargo Project), (2) the Brookings–Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji – Grand Rapids 230 kV Project (the Bemidji Project), and (4) the Twin Cities–LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project. Recovery of OTP’s CapX2020 transmission investments will be through the MISO Tariff (the Brookings Project as an MVP) and Minnesota, North Dakota and South Dakota TCR Riders.

The Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project. The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. Construction is underway for the remaining portions of the project with completion scheduled for second quarter 2015. OTP's share of the costs for the St. Cloud to Fargo portion of the Fargo Project is expected to be \$84.4 million.

The Brookings Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Brookings Project. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project is anticipated to be completed in the first quarter of 2015. OTP's share of the costs for the Brookings Project is expected to be \$26.5 million.

The Bemidji Project—The Bemidji-Grand Rapids transmission line was fully energized and put in service on September 17, 2012.

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 capital structure petition on June 20, 2013, which is in effect until the MPUC issues a new capital structure order for 2014. OTP is required to file its 2014 capital structure petition by May 2014.

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 annually.

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—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.

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. OTP's 2010 NDRRA was in place from September 1, 2010 through March 31, 2012 with a recovery of \$15.6 million. On March 21, 2012 the NDPSC approved an update to OTP's NDRRA effective April 1, 2012. The updated NDRRA recovered

\$9.9 million over the period April 1, 2012 through March 31, 2013. On December 28, 2012 OTP submitted its annual update to the NDRRA with a proposed effective date of April 1, 2013. The update resulted in a rate reduction, so the NDPSC did not issue an order suspending the rate change. Consequently, pursuant to statute, OTP was allowed to implement updated rates effective April 1, 2013 and, on July 10, 2013, the NDPSC approved the rate implemented on April 1, 2013. OTP submitted its annual update to the NDRRA on December 31, 2013 with a proposed April 1, 2014 effective date.

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. On April 29, 2011 OTP filed a request for an initial North Dakota TCR rider with the NDPSC, which was approved on April 25, 2012 and effective May 1, 2012. On August 31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider. The NDPSC approved the annual update on December 12, 2012 with an effective date of January 1, 2013. On August 30, 2013 OTP filed its annual update to its North Dakota TCR rider rate, which was approved on December 30, 2013 and became effective January 1, 2014.

Environmental Cost Recovery Rider—On May 9, 2012 the NDPSC approved OTP's application for an ADP related to the Big Stone Plant AQCS. On February 8, 2013, OTP filed a request with the NDPSC for an ECR rider to recover OTP's North Dakota jurisdictional share of carrying costs associated with its investment in the Big Stone Plant AQCS. On December 18, 2013 the NDPSC approved OTP's North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on and after January 1, 2014. OTP recorded a regulatory asset of \$2.3 million for amounts eligible for recovery through the North Dakota ECR rider that had not been billed to North Dakota customers as of December 31, 2013. The rate will be updated at least annually in a filing with the NDPSC until the project costs are rolled into base rates at an undetermined future date.

Big Stone II Project—On August 27, 2008, the NDPSC determined that OTP's participation in Big Stone II was prudent in a range of 121.8 to 130 MW. On January 20, 2010, OTP filed a request with the NDPSC for a determination that continuing with the Big Stone II project would not have been prudent.

In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC advocacy staff, OTP and the North Dakota Large Industrial Energy Group, as interveners. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excluded \$2.6 million of project transmission-related costs) was determined to be \$10.1 million, of which \$4.1 million represents North Dakota's jurisdictional share. The North Dakota portion of Big Stone II generation costs is being recovered over a 36-month period which began on August 1, 2010.

The North Dakota jurisdictional share of Big Stone II costs incurred by OTP related to transmission was \$1.1 million. Approximately \$0.3 million of the total North Dakota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP during the first quarter of 2013. On July 30, 2013 the NDPSC approved OTP's request to continue the Big Stone II cost recovery rates for an additional eight months through March 31, 2014 to recover the remaining North Dakota share of Big Stone II transmission-related costs plus accrued AFUDC totaling \$1.0 million.

CapX2020 Request for Advance Determination of Prudence—On October 5, 2009 OTP filed an application for an ADP with the NDPSC for its proposed participation in three of the four Group 1 projects: the Fargo Project, the Brookings Project and the Bemidji Project. An administrative law judge conducted an evidentiary hearing on the application in May 2010. On October 6, 2010 the NDPSC adopted an order approving a settlement between OTP and intervener NDPSC advocacy staff, and issued an ADP to OTP for participation in the three Group 1 projects. The order is subject to a number of terms and conditions in addition to the settlement agreement, including the provision of additional information on the eventual resolution of cost allocation issues relevant to the Brookings Project and its associated impact on North Dakota. On April 29, 2011, OTP filed its compliance filing with the NDPSC, seeking a determination of continued prudence for OTP's investment in the Brookings Project. The NDPSC approved the request for an ADP for the Brookings Project on November 10, 2011 conditioned on the MISO MVP cost allocation remaining materially unchanged. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011.

CapX2020 - Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project.

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 transmission lines with a design of 115 kV or more.

2010 General Rate Case—On April 21, 2011, the SDPUC issued a written order approving an overall revenue increase for OTP of approximately \$643,000 (2.32%) and an overall rate of return on rate base of 8.50%. Final rates were effective with bills rendered on and after June 1, 2011.

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 submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. On September 4, 2012 OTP filed its annual update to the South Dakota TCR rider. Updated rates, approved on April 23, 2013, went into effect on May 1, 2013. OTP filed its annual update to the South Dakota TCR rider on August 30, 2013 with a supplemental filing in February 2014 with a proposed implementation date of March 1, 2014.

Big Stone II Project— OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately \$1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP is allowed to earn a return on the amount subject to recovery over the ten-year recovery period. OTP transferred the South Dakota portion of the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP.

A portion of the Big Stone II transmission costs were transferred out of CWIP in February 2013 to be included within the Big Stone South - Brookings MVP. On March 28, 2013, OTP filed a petition with the SDPUC requesting deferred accounting for the remaining unrecovered Big Stone II Transmission costs until OTP's next South Dakota general rate case. The petition was approved by the SDPUC on April 23, 2013 and in May 2013 OTP transferred the remaining South Dakota jurisdictional portion of unrecovered Big Stone II transmission costs plus accumulated AFUDC totaling \$0.2 million from CWIP to the Big Stone II Unrecovered Project Costs – South Dakota long-term regulatory asset account.

Big Stone Plant AQCS—On March 30, 2012 OTP requested approval from the SDPUC for an ECR Rider to recover costs associated with the Big Stone Plant AQCS. On April 17, 2013 OTP filed a request to either suspend or withdraw this filing. The SDPUC approved withdrawing this filing on April 23, 2013. Instead of receiving rider recovery on the portion of AQCS construction costs assignable to OTP's South Dakota customers while the project is under construction, OTP will accrue an AFUDC on these costs and request recovery of, and a return on, the accumulated costs, including AFUDC, in a future rate filing in South Dakota.

CapX2020 Brookings–Southeast Twin Cities 345 kV Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of this project. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project is anticipated to be completed in the first quarter of 2015.

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 June 16, 2010 OTP filed a request with the SDPUC for approval of updates to OTP's 2010 South Dakota EEP and approval for the continuation of the program in 2011. OTP requested increases in energy and demand savings goals and increases in related financial incentives for both 2010 and the requested 2011 program. In an order issued on July 27, 2010 the SDPUC approved OTP's request for updated energy, demand and participation goals for continuation of the EEP into 2011. OTP is operating under its 2010 South Dakota EEP, as updated.

On May 25, 2011 OTP filed a request with the SDPUC for approval of updates to its EEP. The SDPUC approved the 2012-2013 updated EEP with a maximum available incentive payment limited to 30% of the budget amount provided in the EEP, or \$84,000. On June 19, 2012, the SDPUC approved OTP's request for a 2011 financial incentive of \$78,900 along with an increased surcharge adjustment that became effective on July 1, 2012. On June 18, 2013 the SDPUC approved OTP's request for a 2012 financial incentive of \$84,000 along with an increased surcharge adjustment that became effective July 1, 2013. On November 5, 2013, the SDPUC approved OTP's EEP updates for 2014-2015. On December 3, 2013, the SDPUC voted to amend the approval previously given and require OTP to come before the Commission if the overall plan budget would exceed 10%, rather than the previously approved 30%.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935, as amended. 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.

Effective January 1, 2010 the FERC authorized OTP's implementation of a forward looking formula transmission rate under the MISO Tariff. OTP was also authorized by the FERC to recover in its formula rate (1) 100% of prudently incurred CWIP in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects in which OTP is investing: the Fargo Project, the Bemidji Project and the Brookings Project.

On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in MISO 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. On June 7, 2013, in response to a challenge to the MVP cost allocation heard before the United States Court of Appeals, Seventh Circuit, the Court ruled in favor of MISO and MISO transmission owners, issuing an order affirming the FERC's approval of the MVP cost allocation. On October 7, 2013 certain parties submitted a petition for writ of certiorari to the U.S. Supreme Court seeking review of the Seventh Circuit decision. As of February 14, 2014 the U.S. Supreme Court had not acted on the petition.

On November 12, 2013, a group of industrial customers and other stakeholders filed a complaint at the FERC seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the current 12.38% return on equity used in MISO's transmission rates to a proposed 9.15%. MISO and a group of MISO transmission owners have filed responses to the complaint seeking its dismissal and defending the current return on equity. The complaint is pending at the FERC.

Effective on January 1, 2012 the FERC authorized OTP to recover 100% 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.

The Big Stone South – Brookings Project—This planned 345 kV transmission line will extend 70 miles between a proposed substation near Big Stone City, South Dakota and the new Brookings County Substation near Brookings, South Dakota. OTP is jointly developing this project with Xcel Energy. MISO approved this project as an MVP under the MISO Tariff in December 2011. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. A portion of this line is anticipated to use previously obtained Big Stone II transmission route permits and easements and is expected to be in service in 2017. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP. In December 2012, a request was filed with the SDPUC for recertification of a portion of the line route that was approved as part of the Big Stone II transmission development. The SDPUC approved the certification for the northern portion of the route on April 9, 2013. OTP and Xcel Energy jointly submitted an application to the SDPUC for a route permit for the southern portion of the Big Stone South to Brookings line on June 3, 2013. A decision on the permit application for the southern half of this route is expected in

the first quarter of 2014. If the proposed project receives all the necessary approvals, OTP anticipates the line will be completed in 2017. OTP's total capital investment in this project is expected to be approximately \$109 million.

The Big Stone South – Ellendale Project—This transmission line is a proposed 345 kV line that will extend 160 to 170 miles between a proposed substation near Big Stone City, South Dakota and a proposed substation near Ellendale, North Dakota. OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. On August 25, 2013 the NDPSC granted Certificates of Public Convenience and Necessity to OTP and MDU for the ten miles of the proposed line to be built in North Dakota. A joint route permit application was filed by OTP and MDU on August 23, 2013 with the SDPUC. OTP and MDU jointly filed an Application for a Certificate of Corridor Compatibility along with an application for a route permit with the NDPSC on October 18, 2013. If the proposed project receives all the necessary approvals, OTP anticipates the line will be completed in 2019. OTP's total capital investment in this project is expected to be approximately \$184 million.

CapX2020 Brookings Project—In June 2011 the MISO board of directors granted conditional approval of the MVP cost allocation designation under the MISO Tariff for the Brookings Project, and the project was granted unconditional approval in December 2011 as an MVP. This project is anticipated to be completed in the first quarter of 2015.

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 130 members with operations in 48 states and Canada. NAEMA was formed as a successor organization of the Power and Energy Market (PEM) of the Mid-Continent Area Power Pool (MAPP) in recognition that PEM had outgrown the MAPP region. Power pool sales are conducted continuously through NAEMA in accordance with schedules filed by NAEMA with the FERC.

MRO

OTP is a member of the Midwest Reliability Organization (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 North American Electric Reliability Corporation. 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 the territory in the states of South Dakota, Iowa and Wisconsin. The region includes more than 100 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. MRO assumed the reliability functions of the MAPP and Mid-America Interconnected Network, both former voluntary regional reliability councils.

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.

The MISO Energy Markets commenced operation on April 1, 2005. Through its 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) commenced on January 6, 2009. The 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 and the Energy Policy Act of 1992 (which are intended to promote the conservation of energy and the development and use of alternative energy sources) and the Energy Policy Act of 2005.

Competition, Deregulation and Legislation

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

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

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

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, 2013 OTP invested approximately \$103.2 million in environmental control facilities. The 2014 and 2015 construction budgets include approximately \$82 million and \$61 million, respectively, for environmental equipment for existing facilities.

Air Quality - Criteria Pollutants —Pursuant to the federal Clean Air Act (the CAA), the 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. Electrostatic precipitators have been installed at the principal units at the Hoot Lake Plant. Hoot Lake Plant Unit 1, which is the smallest of the three coal-fired units at Hoot Lake Plant, was retired as of December 31, 2005. As a result, OTP believes the units at the Hoot Lake Plant currently meet all presently applicable federal and state air quality and emission standards.

The South Dakota Department of Environment and Natural Resources (DENR) issued a Title V Operating Permit to the Big Stone site on June 9, 2009 allowing for operation of Big Stone Plant. The Big Stone Plant continues to operate under Title V permit provisions. The Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The Coyote Station is equipped with sulfur dioxide (SO₂) removal equipment. The removal equipment—referred to as a dry scrubber—consists of a spray dryer, followed by a fabric filter, and is designed to desulfurize hot gases from the stack. The fabric filter collects spray dryer residue along with the fly ash. The Coyote Station is 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 SO₂ and nitrogen oxides (NO_x).

The national SO₂ 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 SO₂ emissions or acquire allowances from others to achieve compliance. Each allowance is an authorization to emit one ton of SO₂. SO₂ emission requirements are currently being met by all of OTP’s generating facilities without the need to acquire other allowances for compliance with the acid deposition provisions of the CAA.

The national 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 2013.

The EPA Administrator signed the Clean Air Interstate Rule (CAIR) on March 10, 2005. The EPA has concluded that SO₂ and NO_x are the chief emissions contributing to interstate transport of particulate matter less than 2.5 microns (PM_{2.5}). The EPA also concluded that NO_x emissions are the chief emissions contributing to ozone nonattainment. Twenty-three states and the District of Columbia were found to contribute to ambient air quality PM_{2.5} nonattainment in downwind states. On that basis, the EPA proposed to cap SO₂ and NO_x emissions in the designated states. Minnesota was included among the twenty-three states subject to emissions caps; North Dakota and South Dakota were not included. Twenty-five states were found to contribute to downwind 8-hour ozone nonattainment. None of the states in OTP's service territory were slated for NO_x reduction for 8-hour ozone nonattainment purposes. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAIR and the CAIR federal implementation plan in its entirety.

On December 23, 2008, the court reconsidered its order vacating CAIR, instead remanding the rule to the EPA to conduct further proceedings consistent with the court's prior opinion invalidating CAIR. On January 16, 2009, the EPA proposed a rule that would stay the effectiveness of CAIR and the CAIR federal implementation plan for sources in Minnesota while the EPA conducted notice-and-comment rulemaking on remand from the D.C. Circuit's decisions in the litigation on CAIR. Remanding the issue to the EPA for further consideration, the court held that the EPA had not adequately addressed errors alleged by Minnesota Power in the EPA's analysis supporting inclusion of Minnesota. Neither the EPA nor any other party sought rehearing of this part of the court's CAIR decision. Public Notice of the final rule staying the implementation of CAIR in Minnesota appeared in the November 3, 2009 Federal Register.

On July 6, 2010, the EPA proposed the Transport Rule that essentially would replace the CAIR, but which (unlike CAIR) proposed to include Minnesota sources due to a finding that Minnesota's emissions contribute to PM_{2.5} nonattainment in downwind states. However, its impact on Hoot Lake Plant and OTP's Solway combustion turbine under the initial proposal would have been less than what had been contemplated under CAIR. The EPA released the final Transport Rule, renamed as the Cross-State Air Pollution Rule (CSAPR), on July 8, 2011. The final rule made several changes as compared to the proposed rule, including a substantial change in the allowance allocation methodology. A number of states and industry representatives challenged the rule. On December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit granted motions to stay CSAPR pending the court's resolution of the petitions for review. The Court issued an order on August 21, 2012 vacating CSAPR. The order required the EPA to continue administering CAIR pending the promulgation of a valid replacement rule. The United States sought Supreme Court review of the D.C. Circuit's decision vacating CSAPR, and the Supreme Court granted review. Briefing and oral argument took place in late 2013, and a decision on whether CSAPR will be reinstated is expected before July 2014. In the meantime, because no party sought a stay of the issuance of the mandate in the D.C. Circuit pending Supreme Court review, CSAPR remains invalidated, and regulated parties must continue to abide by CAIR pending a Supreme Court decision. Since CAIR is currently stayed for Minnesota, and does not apply to North or South Dakota, there is no impact to OTP at this time.

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 Mercury and Air Toxics Standards (MATS) rule. The final rule became effective on April 16, 2012, and plants will have until April 16, 2015 to comply. However, the EPA is encouraging state permitting authorities to broadly grant a one-year compliance extension to plants that need additional time to install controls. The DENR granted Big Stone Plant a one-year compliance extension in August 2013. The EPA is also providing a pathway for reliability-critical units to obtain an additional year to achieve compliance; however, the EPA has indicated that it believes there will be few, if any situations, in which this pathway is needed. Based on OTP's review of the final rule, it appears that OTP's affected units will meet the requirements by installing the AQCS system at Big Stone, by upgrading the electrostatic precipitators on Hoot Lake Units 2 and 3, by installing activated carbon injection on all units, and by possibly installing dry sorbent injection at Hoot Lake Plant.

Emissions monitoring equipment and/or stack testing will also be needed to verify compliance with the standards. Numerous petitions were filed in the United States Court of Appeals for the D.C. Circuit challenging the MATS rule. The matter has been fully briefed and argued, and a decision is expected in the spring of 2014. Because no stay of the rule was obtained, MATS continues to govern pending resolution of the judicial challenges to the rule.

Air Quality – EPA New Source Review Enforcement Initiative—In 1998 the EPA announced its New Source Review Enforcement Initiative targeting coal-fired utilities, 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. The EPA is attempting 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. On January 2, 2001 OTP received a request from the EPA, pursuant to Section 114(a) of the CAA, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. OTP responded to that request. In March 2003 the EPA conducted a review of the plant’s outage records as a follow-up to its January 2001 data request. A copy of the designated documents was provided to the EPA on March 21, 2003.

On January 8, 2009, OTP received another request from EPA Regions 5 and 8, pursuant to Section 114(a) of the CAA, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant, Coyote Station and Hoot Lake Plant. OTP filed timely responses to the EPA's requests on February 23, 2009 and March 31, 2009. In July 2009, EPA Region 5 issued a follow-up information request with respect to certain maintenance and repair work at the Hoot Lake Plant. OTP responded to the request. The EPA has not set forth any additional follow-up requests at this time. OTP cannot determine what, if any, actions will be taken by the EPA.

Air Quality – Regional Haze Program—The EPA promulgated the Regional Haze Rule in 1999, and on June 15, 2005 the EPA provided final guidelines for conducting BART determinations under the rule. The Regional Haze Rule requires emissions reductions from BART-eligible sources that are deemed to contribute to visibility impairment in Class I air quality areas. Big Stone Plant is BART eligible, and the South Dakota DENR determined that the plant is subject to emission reduction requirements based on the modeled contribution of the plant emissions to visibility impairment in downwind Class I air quality areas. Based on the South Dakota DENR's BART determination and the final South Dakota Regional Haze State Implementation Plan (SIP) approved by the EPA on March 29, 2012, Big Stone must install Selective Catalytic Reduction (SCR) and separated over-fire air to reduce NOx emissions, dry flue gas desulfurization to reduce SO2 emissions, and a new baghouse for particulate matter control. Big Stone Plant must install and operate the BART compliant air quality control system as expeditiously as practicable, but not later than five years after the EPA's final approval of May 29, 2012. The current project cost is estimated to be approximately \$405 million (OTP's share would be \$218 million).

The North Dakota Regional Haze SIP requires that Coyote Station reduce its NOx emissions. On March 14, 2011 the North Dakota Department of Health (NDDOH) issued a construction permit to Coyote Station requiring installation of control equipment to limit its NOx emissions to 0.5 pounds per million Btu as calculated on a 30-day rolling average basis beginning on July 1, 2018. The current estimate of the total cost of the project is \$9 million (\$3.2 million for OTP's share). On March 1, 2012 the EPA signed a final rule for partial approval of the North Dakota SIP that included the NOx emission rate permit conditions for Coyote Station as proposed by the NDDOH. The rule became effective on May 7, 2012.

In June 2012 the Sierra Club and National Parks Conservation Association (NPCA) filed an appeal of the EPA's approval of the North Dakota Regional Haze SIP to the U.S. Court of Appeals for the Eighth Circuit. On the same day Sierra Club/NPCA also separately filed a petition for reconsideration with the EPA. In the petition for reconsideration filed with the EPA, Sierra Club/NPCA did not take issue with the Coyote Station NOx emission limit. However, in the Eighth Circuit appeal, Sierra Club/NPCA filed a brief on October 5, 2012 that included a challenge to the EPA's determinations relative to Coyote Station. The groups requested the Eighth Circuit reverse and remand the EPA's SIP approval. An amicus brief was submitted to the Eighth Circuit on behalf of the Coyote Station on December 18, 2012. Oral arguments were held before the Eighth Circuit on May 14, 2013, and on September 23, 2013 the Eighth Circuit denied the Sierra Club/NPCA appeal with respect to Coyote Station.

Air Quality – Greenhouse Gas (GHG) Regulation—Combustion of fossil fuels for the generation of electricity is a major stationary source of CO2 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 656 MW. In 2013 these plants emitted approximately 4.0 million tons of CO2.

OTP monitors and evaluates the possible adoption of national, regional, or state climate change and GHG legislation or regulations that would affect electric utilities. Congress previously 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 CO₂ emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, is uncertain.

In April 2007, however, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate CO₂ and other GHGs from automobiles as “air pollutants” under the CAA. The Supreme Court directed the EPA to conduct 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; according to the EPA, 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 CO₂ and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride – threaten public health and the environment.

The EPA's final findings respond to the 2007 U.S. Supreme Court decision that GHGs fit within the CAA's definition of air pollutants. The findings do not in and of themselves impose any emission reduction requirements but rather allowed 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 apply to motor vehicles as of January 2011, which makes GHGs "subject to regulation" under the CAA. This, then, triggered the Prevention of Significant Deterioration (PSD) and Title V operating permits programs for stationary sources of GHGs. The question of whether the regulation of motor vehicle emissions does in fact automatically trigger regulation of stationary sources of the same pollutant is presently under review by the Supreme Court. The case is fully briefed, and oral argument will be held on February 24, 2014. A decision is not expected until June or July 2014.

On June 6, 2010 the EPA published a final "tailoring rule" that phases 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 depending on what activities take place at a major source. If triggered, the owner or operator of an affected facility must undergo a review which requires 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.

As of July 2011, sources emitting more than 100,000 tons per year of "CO₂e", a measure that converts emissions of each GHG into its carbon dioxide equivalent, are considered "major sources" subject to PSD requirements if they propose to make modifications resulting in a net GHG emissions increase of 75,000 tons per year or more of CO₂e. OTP does not anticipate making modifications at any of its facilities that would trigger PSD requirements. The South Dakota DENR reviewed OTP's projected emissions, including GHG emissions, as a result of the Big Stone Plant AQCS Project and the DENR agreed that the emissions did not trigger the need for a PSD permit. Consequently, the DENR issued an Air Quality Construction Permit for the Big Stone Plant AQCS Project on January 6, 2012.

Concurrently, the EPA is developing New Source Performance Standards (NSPS) for GHGs from fossil fuel-fired electric generating units. The EPA proposed a rule on January 8, 2014 that would subject large new coal-fired units to a GHG emission limit of 1,100 lbs. of CO₂ per megawatt-hour (mwh) averaged over a 12-month period, or possibly a limit of 1,000-1,050 pounds of CO₂ averaged over a period of seven years. This limit is based on emission reductions the EPA believes could be achieved through the installation and operation of partial carbon capture and sequestration technology. Certain new natural gas-fired units would be subject to a limit of 1,000 or 1,100 pounds of CO₂ per mwh, dependent on unit size, which is the emissions level the EPA believes natural gas combined cycle units can currently achieve with no additional add-ons. Unlike traditional NSPS rules, the proposed GHG NSPS would not apply to modifications at existing units. Under Section 111(b) of the CAA, the EPA must finalize the standard within a year of its proposal, or by January 8, 2015. However, it is expected the EPA will issue a final rule in the second half of 2014. If finalized, the NSPS would apply to any unit the construction of which commences after the date of the proposal, or January 8, 2014.

The EPA also intends to develop GHG performance standards for existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike a NSPS, applies to existing sources of a pollutant. Under Section 111(d), the EPA does not itself issue the standards. Rather, 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 if the EPA finds that the plan is inadequate, the EPA will prescribe a plan for that state. The EPA has indicated that it intends to sign proposed emission guidelines by June 1, 2014, to finalize those guidelines by June 1,

2015 and to require state submissions by June 30, 2016.

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.” In general, the standards ultimately developed are more stringent for new sources than for existing sources, because existing source standards need to consider the issues involved in retrofitting plants considering what can be achieved under their existing design, as well as the cost of implementing the standard relative to the remaining useful life of the facility. The standards also need to be capable of attainment across the category of sources regulated by the standard.

While the potential impact of a 111(d) Standard on OTP's facilities is not yet known, standards of performance for existing sources of GHGs are anticipated to focus on efficiency improvements rather than add-on controls. The cost of efficiency improvements that achieve generation of the same amount of power with less fuel used could be offset in whole or in part by reduced fuel costs. It is also possible that the EPA will allow the states to claim credit for reductions in GHG emissions that are achieved through programs designed to reduce end-user demand and that it will allow the states, either separately or together, to establish emission averaging and emission credit banking and trading systems (i.e., a cap-and-trade program).

Litigation over both the NSPS and the emission guidelines for existing sources is expected. Thus, uncertainty over whether the standards will be enforced or, if so, what will be permitted, may continue for a number of years.

Several states and regional organizations are also developing, or already have developed, 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 electricity 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. Regarding CO₂, the Minnesota legislature set a January 1, 2008 deadline for the MPUC to establish an estimate of the likely range of costs of future CO₂ regulation on electricity generation. The legislation also set state targets for reducing fossil fuel use, included goals for reducing the state's output of GHGs, and restricted importing electricity that would contribute to statewide power sector CO₂ emission. The MPUC, in its order dated December 21, 2007, established an estimate of future CO₂ regulation costs at between \$4/ton and \$30/ton emitted in 2012 and after. However, annual updates of the range are required, and for 2012 and 2013 the range was revised to \$9-\$34/ton, and the start date to begin using CO₂ costs in resource planning decisions was moved from 2012 to 2017.

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.

While the eventual outcome of proposed and pending climate change legislation and GHG regulation is unknown, OTP is taking steps to reduce its carbon footprint and mitigate levels of CO₂ emitted in the process of generating electricity for its customers through the following initiatives:

Supply efficiency and reliability: OTP's efforts to increase plant efficiency and add renewable energy to its resource mix have reduced its CO₂ intensity. Between 1985 and 2013 OTP decreased its overall system average CO₂ emissions intensity by approximately 23%. Further reductions are expected with the additional purchase of 62.4 MW of wind-powered generation under the Ashtabula Wind III wind power purchase agreement, under which energy delivery commenced in October 2013, and with the anticipated replacement of Hoot Lake Plant generation likely with natural gas in the 2020 timeframe.

Conservation: Since 1992 OTP has helped its customers conserve nearly 600 MW of demand and nearly 2.8 million cumulative mwhs of electricity, which is roughly equivalent to the amount of electricity that 232,000 average homes would use in a year. OTP continues to educate customers about energy efficiency and demand-side management and to work with regulators to develop new programs. OTP's 2014-2028 IRP calls for an additional 106 MW of conservation and demand side management impacts by 2028.

Renewable energy: Since 2002, OTP's customers have been able to purchase 100% of their electricity from wind generation through OTP's TailWinds program. OTP has access to 102.9 MW of wind powered generation under power purchase agreements and owns 138 MW of wind powered generation.

Other: OTP is a participating member of the EPA's SF₆ (sulfur hexafluoride) Emission Reduction Partnership for Electric Power Systems program, which proactively is targeting a reduction in emissions of SF₆, a potent GHG. SF₆ has a global-warming potential 23,900 times that of CO₂. Methane has a global-warming potential over 20 times that of CO₂. OTP participates in carbon sequestration research through the Plains CO₂ Reduction Partnership (PCOR) through the University of North Dakota's Energy and Environmental Research Center. The PCOR Partnership is a collaborative effort of approximately 100 public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic CO₂ emissions from stationary sources in central North America.

In late 2009, two federal circuit courts of appeal reversed dismissals of GHG suits and remanded them to district court for trial. OTP was not a party to any of these suits, and does not have an indication that it will be the subject of such a lawsuit. The circuit court opinions, however, opened utility companies and other GHG emitters to these actions, which had previously been dismissed by the district courts as nonjustifiable based on the political question doctrine. In 2010, the U.S. Supreme Court took review of one of these cases, while declining review of another. On June 20, 2011, the Supreme Court ruled unanimously that states cannot invoke federal law to force utilities to cut GHG emissions, which was in agreement with the position of utilities and the EPA.

While the future financial impact of any proposed or pending climate change legislation, litigation, or regulation of GHG emissions is unknown at this time, any capital and operating costs incurred for additional pollution control equipment or CO₂ 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.

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. The EPA announced its decision to proceed with further possible revisions to steam effluent guidelines on September 15, 2009, and published a proposed rulemaking on June 7, 2013. The proposed rulemaking primarily focuses on discharge restrictions applicable to fly ash transport water, bottom ash transport water, and flue gas desulfurization wastewater. Since the steam effluent guidelines rule is not final, at this time OTP is unable to determine how it will affect our facilities, but it appears that the rule could have minimal effect since the facilities do not discharge fly ash transport water, bottom ash transport water, or flue gas desulfurization wastewater into waters of the United States.

On February 16, 2004 the EPA Administrator signed the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. A proposed 316(b) rule was issued on April 20, 2011 to replace the 2004 Phase II rule for existing facilities following its remand by the U.S. Court of Appeals in 2007. Unlike the 2004 Phase II rule, the proposed rule has the potential to affect both Hoot Lake Plant and Coyote Station with the greatest potential effect on Hoot Lake Plant. The final rule is expected to be signed in early 2014, though the EPA has repeatedly missed self-imposed deadlines for finalizing the rule. OTP is uncertain of the impact on the potentially affected facilities until the EPA releases the final rule, and likely until after discussions with state regulatory agencies.

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. Total nameplate rating (manufacturer's expected output) of the five dams is 3,450 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 June 21, 2010 the EPA published a proposed rule that outlines two possible options to regulate disposal of coal ash generated from the combustion of coal by electric utilities under the Resource Conservation and Recovery Act (RCRA). In one option, the EPA would propose to list coal ash destined for disposal in landfills or surface impoundments as “special wastes” subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth the EPA’s hazardous waste regulatory program, which regulates the generation, handling, transport and disposal of wastes.

The proposal would create a new category of special waste under Subtitle C, so that coal ash would not be classified as hazardous waste, but would be subject to many of the regulatory requirements applicable to hazardous waste. This option would subject coal ash to technical and permitting requirements from the point of generation to final disposal. The EPA is considering whether to impose disposal facility requirements such as liners, groundwater monitoring, fugitive dust controls, financial assurance, corrective action, closure of units, and post-closure care. This option also includes potential requirements for dam safety and stability for surface impoundments, land disposal restrictions, treatment standards for coal ash, and a prohibition on the disposal of treated coal ash below the natural water table. Beneficial re-uses of coal ash would not be subject to these requirements.

Under the second proposed regulatory option, the EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for non-hazardous solid wastes. In this option, the EPA is considering issuing national minimum criteria to ensure the safe disposal of coal ash, which would subject disposal units to location standards, composite liner requirements, groundwater monitoring and corrective action standards for releases, closure and post-closure care requirements, and requirements to address the stability of surface impoundments. Within this option, the EPA is also considering not requiring existing surface impoundments to close or install composite liners and allowing them to continue to operate for their useful life.

This option would not regulate the generation, storage, or treatment of coal ash prior to disposal, and no federal permits would be required. The EPA's proposal also states that the EPA is considering whether to list coal ash as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act, and includes proposals for alternative methods to adjust the statutory reportable quantity for coal ash. The EPA has not decided which regulatory approach it will take with respect to the management and disposal of coal ash. It has suggested, however, that if it finalizes a related Clean Water Act rule regarding effluent limitation guidelines for the steam electric power generating category that are expected to drive utilities to dry-handle their coal combustion residues, then an RCRA rule allowing coal ash to be treated as non-hazardous solid waste may be adequate.

Additional requirements may be imposed as part of the EPA's pending rule, which could increase the capital and operating costs of OTP's facilities. Identification of specific costs is contingent on the requirements of the final rule. The most costly option in the EPA proposal is the option that would regulate all coal ash destined for disposal as special waste. For example, under this option, OTP estimates an annual cost of approximately \$5.75 million at its Big Stone Plant. If the EPA chooses the other option, it would impose less cost than this estimate. It is also possible the new regulations would not require change in the current operation and cost of OTP's coal ash disposal sites.

At the request of the Minnesota Pollution Control Agency (MPCA), OTP has 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 (VIC) Program. OTP provided a revised focus feasibility study for remediation alternatives to the MPCA in October 2004. OTP and the MPCA have reached an agreement identifying the remediation technology and OTP completed the projects in 2006. The effectiveness of the remediation is under ongoing evaluation and OTP has notified the MPCA of an additional project in 2014 with plans to remove the ash from one VIC area and place it in OTP's permitted disposal area.

The EPA has promulgated various solid and hazardous waste regulations and guidelines pursuant to, among other laws, the Resource Conservation and Recovery Act of 1976, the Solid Waste Disposal Act Amendments of 1980 and the Hazardous and Solid Waste Amendments of 1984, which provide for, among other things, the comprehensive control of various solid and hazardous wastes from generation to final disposal. The states of Minnesota, North Dakota and South Dakota have also adopted rules and regulations pertaining to solid and hazardous waste. To date, OTP has incurred no significant costs as a result of these laws. The future total impact on OTP of the various solid and hazardous waste statutes and regulations enacted by the federal government or the states of Minnesota, North Dakota and South Dakota is not certain at this time.

In 1980, the United States enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly known as the Federal Superfund law, which was reauthorized and amended in 1986. In 1983, Minnesota adopted the Minnesota Environmental Response and Liability Act, commonly known as the Minnesota Superfund law. In 1988, South Dakota enacted the Regulated Substance Discharges Act, commonly known as the South Dakota Superfund law. In 1989, North Dakota enacted the Environmental Emergency Cost Recovery Act. Among other requirements, the federal and state acts establish environmental response funds to pay for remedial actions associated

with the release or threatened release of certain regulated substances into the environment. These federal and state Superfund laws also establish liability for cleanup costs and damage to the environment resulting from such release or threatened release of regulated substances. The Minnesota Superfund law also creates liability for personal injury and economic loss under certain circumstances. OTP has not incurred any significant costs to date related to these laws. OTP is not presently named as a potentially responsible party under the federal or state Superfund laws.

Capital Expenditures

OTP is continually expanding, replacing and improving its electric facilities. During 2013, approximately \$149 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2013 gross electric property additions, including construction work in progress, were approximately \$474 million and gross retirements were approximately \$60 million. OTP estimates that during the five-year period 2014-2018 it will invest approximately \$657 million for electric construction, which includes \$131 million for OTP's share of the Big Stone Plant AQCS and \$304 million for transmission projects including \$243 million for MVPs and \$26 million for CapX2020 transmission projects (\$7 million for the Brookings to Southeast Twin Cities CapX2020 MVP project is included with the \$243 million for MVP projects). The remainder of the 2014-2018 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, 2013 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, 2013 OTP had 668 equivalent full-time employees. A total of 397 OTP employees are represented by local unions of the International Brotherhood of Electrical Workers under two separate contracts expiring in the fall of 2014 and 2016. 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 and fabrication, and production of material handling trays and horticultural containers.

The Company derived 23%, 24% and 23% of its consolidated operating revenues and 21%, 26% and 22% of its consolidated operating income from the Manufacturing segment for the years ended December 31, 2013, 2012 and 2011, 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 and laser cuts metal components according to manufacturers' specifications primarily for the recreational vehicle, agricultural, lawn and garden, industrial equipment, health and fitness and enclosure industries in its facilities in Detroit Lakes, Otsego and Lakeville, Minnesota, and Washington, Illinois. 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, and serves several major equipment manufacturers in the Peoria, Illinois area and nationwide, including Caterpillar, Komatsu and Gardner Denver.

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. In addition, T.O. Plastics produces products such as clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts for customers in the consumer products, food packaging, electronics, industrial and medical industries, among others. T.O. Plastics' Otsego thermoforming facility achieved an AIB International (formerly American Institute of Baking) compliance rating for producing food-contact packaging materials in its operations.

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.

Backlog

The Manufacturing segment has backlog in place to support 2014 revenues of approximately \$136 million compared with \$124 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 2013, cash expenditures for capital additions in the Manufacturing segment were approximately \$7 million. Total capital expenditures for the Manufacturing segment during the five-year period 2014-2018 are estimated to be approximately \$81 million.

Employees

At December 31, 2013 the Manufacturing segment had 1,059 full-time employees. There are 932 full-time employees at BTM and 127 full-time employees at T.O. Plastics.

PLASTICS

General

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The Company derived 18%, 18% and 15% of its consolidated operating revenues and 25%, 32% and 15% of its consolidated operating income from the Plastics segment for the years ended December 31, 2013, 2012 and 2011, 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. Production facilities are located in Fargo, North Dakota.

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 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 and western United States.

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 areas of competition are a combination of price, service, warranty, and product performance. Northern Pipe and Vinyltech compete not only against other plastic pipe manufacturers, but also ductile iron, steel, concrete and clay pipe producers. Pricing pressure will continue to affect 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 mainly by common carrier.

The PVC resins are acquired in bulk and shipped to point of use by rail car. There are a limited number of third party vendors that supply the PVC resin used by Northern Pipe and Vinyltech. Two vendors provided approximately 93% and 90% of total resin purchases in 2013 and 2012, respectively. 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.

Capital Expenditures

Capital expenditures in the Plastics segment typically include investments in extrusion machines, land and buildings and management information systems. During 2013, cash expenditures for capital additions in the Plastics segment were approximately \$3 million. Total capital expenditures for the five-year period 2014-2018 are estimated to be

approximately \$14 million to replace existing equipment.

Employees

At December 31, 2013 the Plastics segment had 136 full-time employees. Northern Pipe had 89 full-time employees and Vinyltech had 47 full-time employees as of December 31, 2013.

CONSTRUCTION

General

Construction consists of businesses involved in commercial and industrial electric contracting and construction of fiber optic and electric distribution systems, water, wastewater and HVAC systems primarily in the central United States.

The Company derived 17%, 17% and 22% of its consolidated operating revenues and 3%, (15)% and (4)% of its consolidated operating income from the Construction segment for each of the years ended December 31, 2013, 2012 and 2011, respectively. Following is a brief description of the businesses included in this segment:

Foley Company (Foley), headquartered in Kansas City, Missouri, provides mechanical and prime contracting services for water and wastewater treatment plants, power generation plants, hospital and pharmaceutical facilities, and other industrial and manufacturing projects across a multi-state service area in the United States.

Aevenia, Inc. (Aevenia), located in Moorhead, Minnesota, has divisions that provide a full spectrum of electrical design and construction services for the industrial, commercial and municipal business markets, including government, institutional, utility communications and electric distribution.

Competition

Each of the construction companies is subject to competition, as well as the effects of general economic conditions in their respective disciplines and geographic locations. The construction companies must compete with other construction companies primarily in the Upper Midwest and the Central regions of the United States, including companies with greater financial resources, when bidding on new projects. The Company believes the principal competitive factors in the Construction segment are price, quality of work and customer service.

Backlog

The construction companies have backlog in place of \$77 million for 2014 compared with \$151 million one year ago.

Capital Expenditures

Capital expenditures in this segment typically include investments in additional construction equipment. During 2013, cash expenditures for capital additions in the Construction segment were approximately \$5 million. Capital expenditures during the five-year period 2014-2018 are estimated to be approximately \$17 million for the Construction segment.

Employees

At December 31, 2013 there were 426 full-time employees in the Construction segment. There are 232 full-time employees at Foley and 194 full-time employees at Aevenia. Foley has 178 employees represented by various unions, including Carpenters and Millwrights, Laborers, Operating Engineers, Pipe Fitters, Plumbers, Teamsters and Cement Masons. Foley has several labor contracts with various expiration dates in 2014 (124 employees), one contract that expires in March 2015 (14 employees), one contract that expires in April 2017 (8 employees) and one contract that expires in May 2018 (11 employees). Foley also employs 21 people under contracts held by the Tennessee Valley Authority. Foley has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

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.

Discretionary contributions totaling \$20.0 million were made to our defined benefit pension plan in January 2014. We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

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

We had approximately \$39.0 million of goodwill recorded on our consolidated balance sheet as of December 31, 2013. We have recorded goodwill for businesses in each of our business segments except Electric. 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 any of our reporting units may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

We currently have \$7.3 million of goodwill and a \$1.1 million indefinite-lived trade name recorded on our consolidated balance sheet related to the acquisition of Foley in 2003. Foley net earnings improved \$10.4 million between 2012 and 2013. If future expected operating profits do not meet our projections, reductions in anticipated cash flows from Foley may indicate its fair value is less than its book value, resulting in an impairment of some or all of the goodwill and indefinite-lived intangible assets associated with Foley along with a corresponding charge against earnings.

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 \$150 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, 2013 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, 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 44.8% and 54.8%. OTP’s equity-to-total-capitalization ratio was 50.2% as of December 31, 2013.

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. Our dividend payout ratio has exceeded our earnings (losses) in four of the last five years.

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 will have to 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 and the inability to recover the cost of capital additions due to an economic downturn, lack of markets for new products, competition from producers of lower cost or alternative products, product defects or loss of customers. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. Future acquisitions could involve numerous risks including: difficulties in integrating the operations, services, products and personnel of the acquired business; and the potential loss of key employees, customers and suppliers of the acquired business. If we are unable to successfully manage these risks, we could face reductions in net income in future periods.

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

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

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

Our plans to grow and operate our manufacturing and infrastructure businesses could be limited by state law.

Our plans to grow and operate our manufacturing and infrastructure businesses could be adversely affected by legislation in one or more states that may attempt to limit the amount or level of diversification permitted in a holding company structure that includes a regulated utility company or affiliated nonelectric companies.

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 remediation activities of 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 results of operations 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.

We are subject to risks and uncertainties related to the timing of recovery of deferred tax assets which could have a negative impact on our net income in future periods.

If taxable income is not generated in future periods in certain tax jurisdictions the recovery of deferred taxes related to accumulated tax benefits may be delayed and we may be required to record a reserve related to the uncertainty of the timing of recovery of deferred tax assets related to accumulated taxable losses in those tax jurisdictions. This would have a negative impact on the Company's net income in the period the reserve is recorded.

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.

Our electric utility company, OTP, owns electric transmission and generation facilities subject to mandatory and enforceable standards advanced by the North American Electric Reliability Corporation (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. Also, 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-party information processors, are vulnerable to security breach by computer hackers and cyber terrorists.

A successful cyber-attack on the systems that control our generation, transmission, distribution or other assets could severely disrupt business operations, preventing us from serving customers or collecting revenues. 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 maintain property and casualty insurance that may cover certain physical damage or third party injuries caused by potential cybersecurity incidents. However, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available.

OTP is subject to mandatory cybersecurity 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 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.

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), 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. Electric wholesale trading margins could also be adversely affected by losses due to trading activities. 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. 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.

Depending on the outcome of the U.S. Supreme Court review of the 7th Circuit U.S. Court of Appeals decision relating to MVPs, OTP could be required to absorb a disproportionate share of costs for transmission investments if the MISO MVP cost allocation changes. These costs may not be recoverable through a transmission tariff and could result in reduced returns on invested capital and/or increased rates to OTP's retail electric customers. Depending on the outcome of a November 12, 2013 FERC complaint filed by a group of industrial customers and other stakeholders seeking to reduce the return on equity component of the transmission rates that MISO transmission owners, including OTP, may collect under the relevant MISO tariff, OTP may receive a lower return on equity on its MISO transmission rates and this may impact future revenues for transmission services provided in MISO.

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. 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 CO2 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 greenhouse gas emissions, such as mandated levels of renewable generation, mandatory reductions in CO2 emission levels, taxes on CO2 emissions or cap and trade regimes, could require us to incur significant new costs, which could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where OTP provides service or through increased market prices for electricity. Debate continues in Congress on the direction and scope of U.S. 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 CO2 emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, are uncertain. The EPA has begun to regulate GHG emissions under its “endangerment” finding. The EPA has adopted its first GHG emission control rules for motor vehicles and new source review of stationary sources of GHGs, which became applicable to motor vehicles and stationary sources, respectively, on January 2, 2011. The EPA is developing CAA Section 111 standards for GHGs from electric generating units and proposed a rule on September 20, 2013 that would require certain new fossil fuel generating plants to meet a CO2 output based standard. Unlike traditional NSPS rules, the proposed GHG NSPS would not apply to modifications at existing units. It is expected the EPA will issue a final new source rule in 2014. For existing units, the EPA is slated to propose Section 111(d) emission guidelines by June 1, 2014, finalize the guidelines by June 1, 2015, and require states to develop 111(d) plans by June 30, 2016. Specific requirements of the CAA Section 111(d) regulation, and thus their impact on OTP, are uncertain at this time.

MANUFACTURING

Competition from foreign and domestic manufacturers, the price and availability of raw materials 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 have increased significantly and may continue to increase. 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.

Each of our manufacturing companies has significant customers and concentrated sales to such customers. If our relationships with significant customers should change materially, it would be difficult to immediately and profitably replace lost sales.

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 approximately 93% of our total purchases of PVC resin in 2013 and approximately 90% of our total purchases of PVC resin in 2012. 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 PVC pipe manufacturers, but also against ductile iron, steel, concrete and clay 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.

Reductions 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. Reductions in PVC resin prices could negatively affect PVC pipe prices, profit margins on

PVC pipe sales and the value of our finished goods inventory.

CONSTRUCTION

A significant failure or an inability to properly bid or perform on projects or contracts by our construction businesses could lead to adverse financial results and could lead to the possibility of delay or liquidated damages.

The profitability and success of our construction companies require us to identify, estimate and timely bid on profitable projects or contracts. The quantity and quality of projects up for bid at any time is uncertain. Additionally, once a project or contract is awarded, we must be able to perform within cost estimates that were set when the bid was submitted and accepted. A significant failure or an inability to properly bid or perform on projects or contracts could lead to adverse financial results and could lead to the possibility of delay or liquidated damages.

We enter into construction contracts which could expose us to unforeseen costs and costs not within our control, which may not be recoverable and could adversely affect our results of operations and financial condition.

Our construction companies frequently provide services pursuant to fixed-price contracts. Revenues recognized on jobs in progress under fixed-price contracts were \$368 million at December 31, 2013 and \$309 million at December 31, 2012. Under those contracts, we agree to perform the contract for a fixed price and, as a result, can improve our expected profit by superior contract performance, productivity, worker safety and other factors resulting in cost savings. However, we could incur cost overruns above the approved contract price, which may not be recoverable.

Fixed-price contract prices are established based largely on estimates and assumptions relating to project scope and specifications, personnel and material needs. These estimates and assumptions may prove inaccurate or conditions may change due to factors out of our control, resulting in cost overruns, which we may be required to absorb and that could have a material adverse effect on our business, financial condition and results of our operations. In addition, our profits from these contracts could decrease and we could experience losses if we incur difficulties in performing the contracts or are unable to secure fixed-pricing commitments from our suppliers and subcontractors at the time we enter into fixed-price contracts with our customers.

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 three separate generating units. The oldest Hoot Lake Plant generating unit, constructed in 1948 (7,500 kW nameplate rating), was retired on December 31, 2005. A second unit was added in 1959 (53,500 kW nameplate rating) and a third unit was 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. The two generating units in operation have a combined nameplate rating of 128,500 kW.

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, 2013 OTP's transmission facilities, which are interconnected with lines of other public utilities, consisted of 76 miles of 345 kV lines; 487 miles of 230 kV lines; 878 miles of 115 kV lines; and 3,965 miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of 48 miles of the 345 kV lines, with Minnkota Power Cooperative retaining title to the original 230 kV construction. OTP owns an undivided interest in the

remaining 345 kV line miles. OTP is a joint owner, with other regional utilities, in CapX2020 transmission lines with the following ownership interests: 14.8% in the 70 mile Bemidji-Grand Rapids 230 kV line and 13.3% of 29 miles of energized line of the Fargo-Monticello 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 infrastructure business segments. The Company's subsidiaries own construction equipment, tools and facilities and equipment used in: the manufacture of PVC pipe, thermoformed products, heavy metal fabricated products, metal parts stamping, fabricating 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 it 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 the Company's consolidated financial position, results of operations or cash flows.

Item 3A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF MARCH 3, 2014)

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 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, or has served as a director on the Company's Board of Directors.

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
Edward J. McIntyre (63)	9/8/11	Present:	President and Chief Executive Officer
George A. Koeck (61)	4/10/00	Present:	Senior Vice President, General Counsel and Corporate Secretary
Kevin G. Moug (54)	4/9/01	Present:	Chief Financial Officer and Senior Vice President
Charles S. MacFarlane (49)	5/1/03	Present:	Senior Vice President, Electric Platform
Shane N. Waslaski (38)	4/11/11	Present:	Senior Vice President, Manufacturing and Infrastructure Platform

Mr. MacFarlane was appointed President and Chief Operating Officer of the Company effective April 14, 2014.

On September 8, 2011 the Company's Board of Directors appointed current director Edward J. (Jim) McIntyre to serve as interim President and Chief Executive Officer. On January 3, 2012, the Company's Board of Directors appointed Mr. McIntyre to serve as permanent President and Chief Executive Officer of the Company. Mr. McIntyre, 63, is retired Vice President and former Chief Financial Officer of Xcel Energy, Inc. He has been a member of the Board of Directors since 2006.

Mr. Waslaski has worked as a Vice President within the Company's Manufacturing and Infrastructure platform since 2007 and became an executive officer of the Company on April 11, 2011.

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

Item 4.

MINE SAFETY DISCLOSURES

Not Applicable.

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PART II

Item MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND
5. 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 38 of this Annual Report on Form 10-K under the heading "Selected Financial Data," on Page 103 under the heading "Retained Earnings and Dividend Restriction" and on Page 125 under the heading "Supplementary Financial Information." The Company does not have a publicly announced stock repurchase program. In addition, the Company did not repurchase any equity securities during the three months ended December 31, 2013.

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 Index (EEI) over the same period (assuming the investment of \$100 in each vehicle on December 31, 2008, and reinvestment of all dividends).

	2008	2009	2010	2011	2012	2013
OTC	\$ 100.00	\$ 112.40	\$ 108.08	\$ 111.68	\$ 133.49	\$ 162.95
EEI	\$ 100.00	\$ 110.71	\$ 118.50	\$ 142.18	\$ 145.15	\$ 164.03
NASDAQ	\$ 100.00	\$ 143.74	\$ 170.23	\$ 171.23	\$ 202.46	\$ 281.91

Item 6. SELECTED FINANCIAL DATA

(thousands, except number of
shareholders and per-share data)

	2013	2012	2011	2010	2009
Revenues					
Electric	\$ 373,540	\$ 350,765	\$ 342,727	\$ 344,379	\$ 314,666
Manufacturing	204,997	208,965	189,459	143,072	119,255
Plastics	164,957	150,517	123,669	96,945	80,208
Construction	149,910	149,092	184,657	134,222	103,831
Intersegment Eliminations	(91)	(100)	(343)	(721)	(275)
Total Operating Revenues	\$ 893,313	\$ 859,239	\$ 840,169	\$ 717,897	\$ 617,685
Net Income from Continuing Operations	\$ 50,174	\$ 38,968	\$ 34,910	\$ 26,280	\$ 22,131
Net Income (Loss) from Discontinued Operations	691	(44,241)	(48,153)	(27,624)	3,900
Net Income (Loss)	\$ 50,865	\$ (5,273)	\$ (13,243)	\$ (1,344)	\$ 26,031
Operating Cash Flow from Continuing Operations	\$ 150,283	\$ 168,986	\$ 93,678	\$ 105,934	\$ 125,646
Operating Cash Flow - Continuing and Discontinued Operations	147,781	233,547	104,383	105,017	162,750
Capital Expenditures - Continuing Operations	164,463	115,762	67,360	58,264	160,501
Total Assets	1,596,019	1,602,337	1,700,522	1,770,555	1,754,678
Long-Term Debt	389,589	421,680	471,915	430,807	431,083
Basic Earnings Per Share - Continuing Operations (1)	1.37	1.06	0.95	0.71	0.60
Basic Earnings (Loss) Per Share - Total (1)	1.39	(0.17)	(0.40)	(0.06)	0.71
Diluted Earnings Per Share - Continuing Operations (1)	1.37	1.05	0.95	0.71	0.60
Diluted Earnings (Loss) Per Share - Total (1)	1.39	(0.17)	(0.40)	(0.06)	0.71
Return on Average Common Equity (2)	9.5 %	(1.1)%	(2.3)%	(0.3)%	3.8 %
Dividends Declared Per Common Share	1.19	1.19	1.19	1.19	1.19
Dividend Payout Ratio	86 %	—	—	—	168 %
Common Shares Outstanding - Year End	36,272	36,168	36,102	36,003	35,812
Number of Common Shareholders (3)	14,252	14,584	14,687	14,848	14,923

(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 four segments: Electric, Manufacturing, Plastics and Construction. 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 infrastructure businesses will provide 15% to 25% of our earnings, and will continue to be a fundamental part of our strategy.

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 infrastructure 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 segment. 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.

We have worked to realign our portfolio of businesses and refocus our capital investment in the electric utility. Over the last three years we sold several businesses in execution of our announced strategy. In 2011 we sold Idaho Pacific Holdings, Inc. (IPH), our Food Ingredient Processing segment business, and E.W. Wylie Corporation (Wylie), our trucking company which was included in our Wind Energy segment. In January 2012 we sold the assets of Aviva Sports, Inc. (Aviva), a recreational equipment manufacturer and wholly owned subsidiary of Shrco, Inc. (Shrco), our former waterfront equipment manufacturer. In February 2012 we sold DMS Health Technologies, Inc. (DMS), our Health Services segment business. In November 2012 we completed the sale of the assets of IMD, Inc. (IMD), our former wind tower manufacturer, and we exited the wind tower manufacturing business. On February 8, 2013 we sold substantially all of the assets of Shrco.

In evaluating our portfolio of operating companies, we look for the following characteristics:

a threshold level of net earnings and a return on invested capital in excess of our weighted average cost of capital,

a strategic differentiation from competitors and a sustainable cost advantage,

a stable or growing industry,

an ability to quickly adapt to changing economic cycles, and

a strong management team committed to operational excellence.

Major growth strategies and initiatives in our future include:

Planned capital budget expenditures of up to \$769 million for the years 2014 through 2018, of which \$657 million are for capital projects at Otter Tail Power Company (OTP), including \$131 million for OTP's share of a new air quality control system at Big Stone Plant and \$304 million for anticipated expansion of transmission capacity including \$243 million for Midcontinent Independent System Operator, Inc. (MISO) designated Multi-Value Projects (MVPs) and \$26 million for Capacity Expansion 2020 (CapX2020) transmission projects (\$7 million for the Brookings to Southeast Twin Cities CapX2020 MVP project is included with the \$243 million for MVP projects). The remainder of the OTP 2014-2018 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant. See "Capital Requirements" section for further discussion.

Utilization of existing and potentially expanded plant capacity from capital investments made in our manufacturing and infrastructure businesses.

Continued investigation and evaluation of organic growth opportunities and evaluation of opportunities to allocate capital to potential acquisitions in our Manufacturing segment.

In 2013:

Our net cash from continuing and discontinued operations was \$147.8 million.

Our Construction segment recorded net income of \$1.3 million compared with a net loss of \$7.7 million in 2012. Net income from Foley Company (Foley), our mechanical and prime contractor on industrial projects was \$0.5 million compared to a net loss in 2012 of \$10.0 million as a result of cost overruns on several large jobs which were

substantially complete by the end of 2012.

Our Manufacturing segment net income increased 7.3% to \$11.5 million from \$10.7 million in 2012.

Our Electric segment net income of \$38.2 million decreased slightly from \$38.3 million in 2012.

Our Plastics segment net income decreased 2.2% to \$13.8 million from \$14.1 million in 2012.

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

(in thousands)	2013	2012
Operating Revenues:		
Electric	\$ 373,459	\$ 350,679
Manufacturing and Infrastructure	519,854	508,560
Total Operating Revenues	\$ 893,313	\$ 859,239
Net Income (Loss) From Continuing Operations:		
Electric	\$ 38,236	\$ 38,341
Manufacturing and Infrastructure	26,576	17,100
Corporate	(14,638)	(16,473)
Total Net Income From Continuing Operations:	\$ 50,174	\$ 38,968

Revenue increases in our Electric, Plastics and Construction segments were partially offset by a decrease in revenues from our Manufacturing segment, resulting in a 4.0% increase in consolidated revenues in 2013 compared with 2012. Revenues from our Electric segment increased \$22.8 million reflecting: (1) a \$20.2 million increase in retail revenue as a result of a 5.8% increase in retail kilowatt-hour (kwh) sales due mainly to colder weather in 2013 evidenced by a 37% increase in heating degree days between the years, and (2) a \$1.9 million increase in wholesale revenues from excess generation as a result of a 15.9% increase in prices received on wholesale energy sales. Revenues from our Plastics segment increased \$14.4 million as a result of a 12.0% increase in pounds of polyvinyl chloride (PVC) pipe sold partially offset by lower PVC pipe prices. Revenues from our Construction segment increased \$0.8 million as a \$16.5 million increase in revenue at Foley was mostly offset by a \$15.7 million decrease in revenues at Aeveenia, Inc. (Aeveenia) our electrical design and construction services company, \$5.4 million of which relates to Aeveenia's sale of Moorhead Electric in October of 2012. Revenues from our Manufacturing segment decreased \$4.0 million as a result of the discontinued production of a major packaging product for a customer who took production in-house and lower sales volume due to reduced demand from customers in end markets serving the construction and energy industries.

The following table sets forth actual 2013 consolidated diluted earnings per share results from continuing operations against the last forecast we provided for 2013 on a GAAP basis, and also shows the effect on a non-GAAP basis of the November 2013 early retirement of \$47.7 million of our previously outstanding \$100 million 9.000% Notes due December 15, 2016.

	2013 Earnings Per Share Guidance Range December 2, 2013		2013 Earnings Per Share	2012 Earnings Per Share
	Low	High		
Electric	\$1.02	\$1.04	\$1.05	\$1.06
Manufacturing	\$0.30	\$0.33	\$0.32	\$0.29
Plastics	\$0.35	\$0.37	\$0.38	\$0.39
Construction	\$0.03	\$0.05	\$0.04	(\$0.21)
Corporate – Recurring Costs	(\$0.32)	(\$0.29)	(\$0.25)	(\$0.22)
Subtotal – Non-GAAP Basis ¹	\$1.38	\$1.50	\$1.54	\$1.31
Corporate – Loss on Debt Extinguishment	(\$0.17)	(\$0.17)	(\$0.17)	(\$0.22)
Corporate – Interest on Debt Related to Discontinued Operations				(\$0.04)
Total – Continuing Operations - GAAP Basis	\$1.21	\$1.33	\$1.37	\$1.05

¹In November 2013 we retired early \$47.7 million of our previously outstanding \$100 million 9.000% Notes due December 15, 2016 from available cash. In July 2012 we retired early our \$50 million, 8.89% Senior Unsecured Note

due November 30, 2017 from proceeds generated in connection with the divestiture of IMD. Generally Accepted Accounting Principles require that in order for debt retirement premiums and related interest expense to be reported as discontinued operations, a company must be required by the lender to repay the related debt as a result of the disposition. Although we were not legally obligated to repay the aforementioned \$50 million note, management believes it is appropriate to associate the 2012 debt prepayment premium and interest expense with its discontinued operations to provide a better indication of future earnings. 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. 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, 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 in accordance with GAAP.

Following is a more detailed analysis of our operating results by business segment for the years ended December 31, 2013, 2012 and 2011, followed by a discussion of our financial position at the end of 2013 and our outlook for 2014.

RESULTS OF OPERATIONS

This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes. See note 2 to our 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 2013, 2012 and 2011 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)	2013	2012	2011
Operating Revenues:			
Electric	\$ 81	\$ 86	\$ 94
Nonelectric	10	14	249
Cost of Goods Sold	20	68	122
Other Nonelectric Expenses	71	32	221

ELECTRIC

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

(in thousands)	2013	% change	2012	% change	2011
Retail Sales Revenues	\$328,758	7	\$308,530	1	\$304,181
Wholesale Revenues – Company Generation	14,846	15	12,951	(11)	14,518
Net Revenue – Energy Trading Activity	1,615	13	1,426	(39)	2,319
Other Revenues	28,321	2	27,858	28	21,709
Total Operating Revenues	\$373,540	6	\$350,765	2	\$342,727
Production Fuel	71,248	7	66,284	(4)	69,017
Purchased Power – System Use	52,006	6	49,184	13	43,451
Other Operation and Maintenance Expenses	133,395	10	121,069	4	115,863
Asset Impairment	--	--	432	(8)	470
Depreciation and Amortization	43,125	3	42,051	4	40,283
Property Taxes	11,311	6	10,720	5	10,190
Operating Income	\$62,455	2	\$61,025	(4)	\$63,453
Electric kwh Sales (in thousands)					
Retail kwh Sales	4,487,541	6	4,240,789	(1)	4,291,637
Wholesale kwh Sales – Company Generation	471,474	(1)	476,637	(7)	510,978
Wholesale kwh Sales – Purchased Power					
Resold	172,404	95	88,637	(28)	122,430
Heating Degree Days	7,366	37	5,377	(15)	6,318
Cooling Degree Days	516	(20)	641	20	534

2013 compared with 2012

Retail sales revenues increased by \$20.2 million as a result of:

a \$6.6 million increase in revenues due to significantly colder weather in 2013 compared to 2012, which drove a 5.8% increase in retail kwh sales,

a \$7.0 million increase in retail revenue related to increases in fuel clause adjustment revenues and fuel and purchased power costs recovered in base rates, which was driven by increased kwh generation to meet higher retail demand and higher prices for purchased power,

a \$2.8 million increase in transmission cost recovery rider revenues resulting from increased investment in transmission lines,

a \$2.3 million increase in environmental cost recovery revenues related to earning a return in North Dakota on funds invested in the construction of a new air quality control system at Big Stone Plant, and

a \$1.5 million increase in conservation improvement program recovered costs and incentives earned as a result of the effectiveness of OTP's programs.

Wholesale electric revenues from company-owned generation increased \$1.9 million, despite a 1.1% decline in wholesale kwh sales, due to a 15.9% increase in the average price per wholesale kwh sold, which was driven by higher natural gas prices and increased demand resulting from colder weather in 2013.

Net revenue from energy trading activities, including net mark-to-market gains on forward energy contracts, increased \$0.2 million mainly as a result of an increase in unrealized mark-to-market gains on open energy contracts scheduled to settle in January and February of 2014.

Other electric operating revenues increased \$0.5 million reflecting a \$2.6 million increase in MISO tariff revenues related to increasing investments in regional transmission projects, mainly CapX2020 projects, offset by a \$2.2 million reduction in revenue from shared use of transmission facilities with other regional transmission providers. 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.

The \$5.0 million increase in production fuel costs resulted from a 10.8% increase in kwhs generated from OTP's steam-powered and combustion turbine generators, partially offset by a 3.0% reduction in the cost of fuel per kwh generated. The increase in kwh generation was facilitated by improved availability of all of OTP's steam-powered generation units in 2013. The increase in generation was dedicated entirely to serving increased demand from OTP's retail customers driven by colder weather in 2013. The cost of purchased power to serve retail customers increased \$2.8 million, despite a 2.1% decrease in kwhs purchased, due to an 8.0% increase in costs per kwh purchased driven by increased demand and higher fuel prices for natural-gas fired generation.

Electric operating and maintenance expenses increased \$12.3 million as a result of the following:

- a \$4.0 million increase in MISO transmission tariff charges related to increasing investments in regional CapX2020 and MISO-designated MVP transmission projects,

- a \$2.9 million increase in corporate costs allocated to OTP due, in part, to changes in allocation factors resulting from the corporation's recent divestitures,

- a \$2.5 million increase in labor and benefit expenses due to increases in salaries and wages, a reduction in capitalized labor in 2013 compared with 2012 and an increase in pension benefit costs resulting from a reduction in the discount rate related to projected benefit obligations,

- a \$0.8 million increase in transportation costs related to higher gasoline prices and a reduction in capitalized transportation expenses in 2013,

- a \$0.7 million discount on OTP's investment in abandoned transmission plant that was transferred in 2013 from construction work in progress to a regulatory asset account for future recovery,

- a \$0.4 million increase in conservation improvement program costs, and

\$1.0 million total increased expenditures for insurance, outside services, vegetative maintenance, power plant water supply and bad debt expense in 2013.

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Otter Tail Energy Services Company (OTESCO) recorded a \$0.4 million asset impairment charge related to wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota in the first quarter of 2012 as a potential sale of the rights did not occur as expected. OTESCO ceased operations and did not record any operating revenues, expenses or net income in 2013.

The \$1.1 million increase in depreciation expense is mainly related to CapX2020 transmission lines being placed in service in 2013.

Property taxes increased \$0.6 million due to higher property value assessments in Minnesota and South Dakota.

2012 compared with 2011

Retail sales revenues increased by \$4.3 million as a result of:

- a \$2.6 million increase in transmission cost recovery revenues as a result of increased investment in transmission assets,

- a \$1.8 million interim rate refund recorded in 2011 related to amounts collected under interim rates in Minnesota in 2010,

- a \$1.5 million increase in revenue mainly related to rate design changes implemented in Minnesota in October 2011 on finalization of OTP's 2010 general rate case, and

- a \$0.9 million increase in retail revenue related to the recovery of increased fuel and purchased power costs,

offset by:

- a \$2.3 million decrease in revenues related to a 1.2% reduction in retail kwh sales between the periods due to a reduction in heating-degree days resulting from significantly milder weather in the first half of 2012 compared to the first half of 2011, partially offset by an increase in cooling-degree days in the summer of 2012 compared with the same period in 2011, and

- a \$0.2 million reduction in accrued conservation program cost recovery revenues and incentives.

Wholesale electric revenues from company-owned generation decreased \$1.6 million due to a 6.7% decline in wholesale kwh sales in combination with a 4.4% decrease in the average price per wholesale kwh sold. This was related to an 8.7% reduction in kwh generation mainly as a result of two major shutdowns of OTP's lowest-cost baseload resource, Coyote Station, in 2012. The first occurred in the second quarter of 2012 for seven weeks of scheduled maintenance, and the second occurred on November 27, 2012, when an electrical fault caused major damage to the station's generator, which needed to be moved offsite for repairs that took 11 weeks. Lower demand in wholesale markets and low natural gas prices for alternative generation also contributed to the reduction in wholesale electric sales.

Net revenue from energy trading activities, including net mark-to-market gains on forward energy contracts, decreased \$0.9 million mainly as a result of a decrease in mark-to-market gains on open energy contracts, along with a reduction in trading activity.

Other electric operating revenues increased \$6.1 million as a result of:

- a \$3.6 million increase in MISO Schedule 26 transmission tariff revenues, driven in part by returns on, and recovery of, CapX2020 investment costs and operating expenses,

- a \$1.5 million increase in revenues earned under agreements for shared use of transmission facilities with other regional transmission providers,

- \$0.9 million in MISO Schedule 26A revenue, new in 2012, mainly related to investments in MISO designated MVPs,

\$0.8 million in revenue earned under a contract to upgrade a distribution system for another regional electric service provider, and

a \$0.7 million increase in MISO Schedule 1 transmission tariff revenues due to 2011 and 2012 changes in the calculation methodology used to determine Schedule 1 revenues,

offset by:

a \$1.3 million reduction in revenue related to payments received in 2011 from a transmission cooperative to OTESCO for access rights to construct a high voltage transmission line through a wind farm site where OTESCO owned development rights, and for assistance in obtaining easements from landowners.

The \$2.7 million decrease in production fuel costs resulted from a 9.0% decrease in kwhs generated from OTP's steam-powered and combustion turbine generators, partially offset by a 5.5% increase in the cost of fuel per kwh generated. The decrease in kwh generation was due to the two major maintenance shutdowns of Coyote Station in 2012. The cost of purchased power for retail sales increased \$5.7 million as a result of a 28.2% increase in kwhs purchased for system use, partially offset by an 11.7% decrease in the cost per kwh purchased. The increase in kwh purchases was driven by the need to buy replacement power after Coyote Station went off-line in November 2012.

Electric operating and maintenance expenses increased \$5.2 million due to the following:

a \$3.4 million increase in MISO transmission service charges, mainly MISO Schedule 26 charges related to increased investment in transmission facilities by MISO member companies,

a \$2.2 million increase in labor and benefit expenses mainly due to increases in pension and retiree health benefit costs resulting from a reduction in the discount rate applied to projected benefit obligations,

a \$1.1 million increase in maintenance expenses at Coyote Station related to its second quarter 2012 seven-week scheduled major maintenance shutdown,

a \$0.4 million increase in wind farm maintenance service costs, and

a \$0.3 million increase in maintenance costs at Big Stone Plant,

offset by:

a \$1.7 million reduction in material and supply costs related to costs incurred in conjunction with a major overhaul of Big Stone Plant in the fourth quarter of 2011, and

a \$0.4 million reduction in incurred conservation program costs, commensurate with a reduction in accrued revenues related to the future recovery of those costs.

OTESCO recorded asset impairment charges of \$0.4 million in the first quarter of 2012 and \$0.5 million in the fourth quarter of 2011 related to its wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota, based on market indicators of the value of those assets.

The \$1.8 million increase in depreciation expense is related to 2011 property additions, mainly transmission assets.

Property taxes increased \$0.5 million due to higher taxes on electric distribution property and increased investments in transmission property.

MANUFACTURING

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

(in thousands)	2013	% change	2012	% change	2011
Operating Revenues	\$ 204,997	(2)	\$ 208,965	10	\$ 189,459
Cost of Products Sold	154,235	(2)	157,437	9	144,987
Other Operating Expenses	18,820	3	18,233	10	16,524
Depreciation and Amortization	11,194	(8)	12,208	1	12,116
Operating Income	\$ 20,748	(2)	\$ 21,087	33	\$ 15,832

2013 compared with 2012

The decrease in revenues in our Manufacturing segment in 2013 compared with 2012 relates to the following:

Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, decreased \$1.7 million (1.0%) as a result of lower sales volume due to reduced demand from customers in end markets serving the construction and energy industries, partially offset by increased sales to customers in end markets serving the recreational equipment and agricultural industries.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) our manufacturer of thermoformed plastic and horticultural products, decreased \$2.3 million (5.7%) due to the discontinuance of a packaging product for a major customer who took production of the product in-house, partially offset by increased sales volumes in certain horticultural and industrial product lines.

The decrease in cost of products sold in our Manufacturing segment in 2013 compared with 2012 consists of the following:

Cost of products sold at BTD decreased by \$0.1 million as a reduction in costs related to lower sales volumes was mostly offset by increases in labor costs due to a ramp up in hiring personnel in anticipation of larger sales volumes in 2014.

Cost of products sold at T.O. Plastics decreased \$3.1 million as a result of reductions in raw material costs and reduced conversion costs related to productivity improvements.

The increase in other operating expenses in our Manufacturing segment in 2013 compared with 2012 relates to the following:

Operating expenses at BTD increased \$0.2 million mainly as a result of upgrades and enhancements made to BTD's communications systems.

Operating expenses at T.O. Plastics increased \$0.4 million as a result of increased hiring costs associated with new management team members and increased sales incentives and commissions.

Depreciation expense decreased mainly as a result of certain assets at BTD's Illinois plant being fully depreciated early in 2013.

2012 compared with 2011

The increase in revenues in our Manufacturing segment in 2012 compared with 2011 relates to the following:

Revenues at BTD increased \$17.7 million (11.8%) as a result of higher sales volume due to improved customer demand for products and services.

Revenues at T.O. Plastics increased by \$1.8 million (4.6%) mainly as a result of increased sales of industrial and medical products.

The increase in cost of products sold in our Manufacturing segment in 2012 compared with 2011 consists of the following:

Cost of products sold at BTD increased \$12.4 million mainly as a result of increased sales volume.

Cost of products sold at T.O. Plastics increased \$0.1 million. An increase in costs related to the increase in sales of industrial and medical products was mostly offset by productivity improvements from the use of different blends of plastics and improved operating efficiencies along with more selective bidding practices.

The increase in other operating expenses in our Manufacturing segment in 2012 compared with 2011 relates to the following:

Operating expenses at BTD increased \$1.7 million mainly due to increased benefit expenses related to employee incentives, but also due to increased salary and benefit expenses related to workforce expansion and increases in expenditures for contracted services.

Operating expenses at T.O. Plastics were unchanged between the years.

PLASTICS

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

(in thousands)	2013	% change	2012	% change	2011
Operating Revenues	\$ 164,957	10	\$ 150,517	22	\$ 123,669
Cost of Products Sold	129,042	15	112,662	9	103,131

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Operating Expenses	8,571	(2)	8,784	41	6,210
Depreciation and Amortization	3,350	7	3,118	(8)	3,377
Operating Income	\$ 23,994	(8)	\$ 25,953	137	\$ 10,951

2013 compared with 2012

The increase in Plastics segment revenue is the result of a 12.0% increase in pounds of PVC pipe sold, partially offset by a 2.2% decrease in the price per pound of pipe sold. Sales volume increased as construction and housing markets continued to improve in the South Central and Southwest regions of the United States and construction activity increased in the North Central United States in the second half of 2013. The increase in costs of products sold was mostly due to the increase in pounds of pipe sold, but also reflects a 2.2% increase in the cost per pound of pipe sold related to higher PVC resin costs driven by high global demand and an increase in the cost of ethylene, a key ingredient in the production of PVC resin. The reduction in operating expenses reflects a reduction in incentive compensation related to the decrease in operating income between the years. The increase in depreciation and amortization expense is related to equipment replacement costs incurred in 2013 at our Arizona plant associated with increased production levels and machine usage.

2012 compared with 2011

The \$26.8 million increase in Plastics operating revenues in 2012 compared with 2011 was due to a 17.0% increase in pounds of PVC pipe sold combined with a 4.1% increase in the price per pound of PVC pipe sold. The \$9.5 million increase in cost of products sold was related to the increase in pounds of PVC pipe sold offset by a 6.6% reduction in the cost per pound of pipe sold. The decrease in the cost per pound of pipe sold was due to lower prices of resin between the years and increased productivity as fixed production costs were spread over a larger volume of pipe produced over longer production runs with less downtime. The \$2.6 million increase in operating expenses is mainly due to increased employee incentives related to improved operating results, but also reflects increases in commissions related to the increase in sales volume.

CONSTRUCTION

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

(in thousands)	2013	% change	2012	% change	2011
Operating Revenues	\$ 149,910	1	\$ 149,092	(19)	\$ 184,657
Cost of Construction Revenues					
Earned	133,430	(9)	147,107	(15)	173,654
Operating Expenses	11,855	(4)	12,353	4	11,886
Depreciation and Amortization	2,009	5	1,906	(5)	2,009
Operating Income (Loss)	\$ 2,616	--	\$ (12,274)	(324)	\$ (2,892)

2013 compared with 2012

Revenues in our Construction segment were relatively flat in 2013 compared with 2012, but our individual operating companies experienced significant changes in revenue due to the following:

Revenues at Foley increased \$16.5 million (17.6%) mainly as a result of recognizing revenue in 2013 on several large projects initiated in 2012. Also, in 2012, increases in costs on certain projects in excess of initial estimates resulted in declining levels of revenue recognized relative to costs incurred and an erosion of margins on those projects under percentage-of-completion accounting.

Revenues at Aevenia decreased \$15.7 million (28.3%) as a result of a decrease in construction activity due to a strategic reduction in the volume of telecommunications jobs pursued in 2013 and a harsher winter and colder and wetter spring in 2013 that delayed the start of many construction projects relative to the early start to construction that was facilitated by extremely mild weather in the first six months of 2012. Aevenia's 2012 revenues also included \$5.4 million from Moorhead Electric, Inc. (MEI), an Aevenia subsidiary that was sold in October 2012.

The decrease in cost of construction revenues earned in our Construction segment in 2013 compared with 2012 relates to the following:

Cost of construction revenues earned at Foley decreased \$0.6 million despite the large increase in Foley's revenues as a result of a reduction in cost overruns on major projects nearing completion during the periods, mostly offset by an increase in costs related to the increased volume of work completed in 2013 on several large projects that were initiated in 2012. As a result of these revenue and cost changes, Foley went from recording a \$15.9 million operating loss in 2012 to recording \$1.1 million in operating income in 2013.

Cost of construction revenues earned at Aevenia decreased \$13.1 million as a result of a decrease in construction activity due to the strategic reduction in telecommunications jobs pursued in 2013 and the harsher winter and colder and wetter spring in 2013 delaying the start of many construction projects, and due to the sale of MEI in October 2012. MEI's cost of goods sold totaled \$4.5 million in 2012.

The decrease in other operating expenses in our Construction segment in 2013 compared with 2012 relates to the following:

Operating expenses at Foley increased \$0.2 million as a result of minor increases in several categories of expense in 2013, which can be attributed to an increase in the level of Foley's business activity in 2013.

Operating expenses at Aevenia decreased \$0.7 million between the years: \$0.5 million as a result of the sale of MEI in October 2012, and \$0.2 million related to a reduction in gains from sales of assets.

2012 compared with 2011

The decrease in revenues in our Construction segment in 2012 compared with 2011 relates to the following:

Revenues at Foley decreased \$48.3 million (34.0%) due to a decrease in work volume and the effect of cost overruns on estimated revenues recognized under percentage-of-completion accounting, where revenues are recognized during the project based on the ratio of actual costs incurred to total estimated costs to complete the job. Under percentage-of-completion accounting, increases in costs on certain projects of \$14.9 million in 2012 and \$7.0 million in 2011 in excess of initial estimates resulted in declining levels of revenue recognized relative to costs incurred and an erosion of margins on those projects.

Revenues at Aevenia increased \$12.7 million (29.6%) mainly due to an increase in electrical transmission, distribution and substation work in the oil patch region of western North Dakota.

The decrease in cost of construction revenues earned in our Construction segment in 2012 compared with 2011 relates to the following:

Cost of construction revenues earned at Foley decreased \$35.8 million. The decrease reflects reductions in material and subcontractor costs due to a decrease in work volume between periods.

Cost of construction revenues earned at Aevenia increased \$9.2 million as a result of the increase in electrical transmission, distribution and substation work, which drove increases in labor, material, subcontractors and rent costs.

The increase in other operating expenses in our Construction segment in 2012 compared with 2011 relates to the following:

Operating expenses at Foley increased \$0.3 million as a result of increased expenditures for outside services.

Operating expenses at Aevenia increased \$0.1 million as a result of increased expenditures for outside services.

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)	2013	% change	2012	% change	2011
Operating Expenses	\$ 12,755	(4)	\$ 13,283	(11)	\$ 14,897
Depreciation and Amortization	207	(57)	481	(13)	550

The \$0.5 million decrease in Corporate operating expenses in 2013 compared with 2012 reflects:

a \$2.9 million increase in various corporate expenses allocated or directly charged to our Electric segment due, in part, to changes in allocation factors resulting from the corporation's recent divestitures, and

a \$0.5 million reduction in insurance costs and contracted services,

offset by:

a \$2.4 million increase in incentive and performance award accruals related to our improved operating results and the strong performance of our common stock price as measured against the stock performances of our peer group of companies in the Edison Electric Institute Index, and

a \$0.5 million increase in labor costs mainly related to staffing additions at Varistar Corporation (Varistar).

Corporate operating expenses were lower in 2012 than in 2011 as a result of termination benefits incurred in the third quarter of 2011 associated with the resignation of the Company's former chief executive officer and reductions in health benefit costs.

LOSS ON EARLY RETIREMENT OF DEBT

On November 6 and 25, 2013 we purchased, in two separate transactions, approximately \$47.7 million of our outstanding \$100 million 9.000% Notes due December 15, 2016 (the 2016 Notes). The purchased Notes (Purchased 2016 Notes) were subsequently retired and are no longer outstanding. The price we paid for the Purchased 2016 Notes was approximately \$59.4 million, which includes the principal amount of the Purchased 2016 Notes, plus accrued interest of approximately \$1.8 million through the respective purchase dates and a negotiated premium of approximately \$9.9 million (which was less than the redemption premium we would have been required to pay under the terms of the 2016 Notes). On repayment, \$0.4 million in unamortized debt expense related to the 2016 Notes was immediately recognized as expense along with the \$9.9 million negotiated premium. We used cash on hand to fund the purchase of the Purchased 2016 Notes. The amount of the debt retired as a result of these transactions is approximately equivalent to the remaining amount of debt that was associated with the operating companies we divested over the last two years. The retirement of the Purchased 2016 Notes reduces pre-tax interest expense by approximately \$4.3 million per year for the remaining three-year life of the Purchased 2016 Notes. The \$10.3 million (\$6.2 million net-of-tax) loss on early retirement of debt had a negative impact on 2013 diluted earnings per share of \$0.17.

On July 13, 2012 we prepaid in full our \$50 million 8.89% Senior Unsecured Note due November 30, 2017 (the Cascade Note). The price to prepay the Cascade Note was \$63.0 million which included the principal amount of the Cascade Note plus accrued interest of \$0.5 million and a negotiated prepayment premium of \$12.5 million. On repayment, \$0.6 million in unamortized debt expense related to this note was immediately recognized as expense along with the \$12.5 million negotiated prepayment premium. The \$13.1 million (\$7.9 million net-of-tax) loss on early retirement of debt had a negative impact on 2012 diluted earnings per share of \$0.22.

CONSOLIDATED INTEREST CHARGES

The \$4.9 million decrease in interest charges in 2013 compared with 2012 reflects the following:

- a \$2.7 million decrease in interest and debt amortization charges related to the retirement of the Cascade Note on July 13, 2012,

- a \$0.6 million net decrease in interest charges as a result of OTP's debt refinancing on March 1, 2013, when it borrowed \$40.9 million under an unsecured term loan due January 15, 2015, bearing interest at LIBOR plus 0.875% and used a portion of the proceeds to redeem its \$20.1 million in outstanding 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds and \$5.1 million in outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds,

- a \$0.5 million reduction in interest charges as a result of the early retirement in November 2013 of \$47.7 million of our outstanding 9.000% Notes,

- a \$0.4 million reduction in line of credit non-use fees as a result of reducing the Otter Tail Corporation line limit by \$50 million in October 2012,

- a \$0.3 million increase in capitalized interest expense at OTP related to OTP's increasing investment in the Big Stone Plant air quality control system (AQCS), and

- a \$0.3 million decrease in interest on the Company's and OTP's line of credit borrowings.

Interest charges decreased \$3.7 million in 2012 compared with 2011 due to a \$2.0 million reduction in interest expense related to the retirement of the Cascade Note on July 13, 2012, a \$1.2 million reduction in short-term debt interest related to a \$38.8 million reduction in the daily average balance of short-term debt outstanding between the years, and a \$0.6 reduction in the amortization of debt issuance expense and reacquisition losses on OTP debt.

CONSOLIDATED OTHER INCOME

Other income was \$4.1 million for both 2013 and 2012. Other income increased \$1.3 million in 2012 compared with 2011 due to an increase of \$1.0 million in investment income and gains on investments, and a \$0.3 million increase in Allowance for Funds Used during Construction.

CONSOLIDATED INCOME TAXES

Income tax expense - continuing operations was \$13.5 million in 2013 compared with \$2.1 million in 2012 and \$4.1 million in 2011. 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 years ended December 31, 2013, 2012 and 2011:

	For the Year Ended December 31,					
(in thousands)	2013		2012		2011	
Tax Computed at Federal Statutory Rate	\$22,301		\$14,385		\$13,661	
Increases (Decreases) in Tax from:						
Federal Production Tax Credit (PTC)	(6,612	)	(6,695	)	(7,281	)
State Income Taxes Net of Federal Income Tax Benefit	1,667		(849	)	798	
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(863	)	(891	)	(996	)
Corporate Owned Life Insurance	(856	)	(585	)	(388	)
Allowance for Funds Used During Construction - Equity	(638	)	(409	)	(301	)
Dividend Received/Paid Deduction	(632	)	(656	)	(677	)
Investment Tax Credit Amortization	(597	)	(720	)	(855	)
Tax Depreciation - Treasury Grant for Wind Farms	(304	)	(304	)	(507	)
Differences Reversing in Excess of Federal Rates	(100	)	(143	)	680	
Impact of Medicare Part D Change	--		(584	)	(599	)
Permanent and Other Differences	177		(416	)	586	
Total Income Tax Expense – Continuing Operations	\$13,543		\$2,133		\$4,121	
Effective Income Tax Rate – Continuing Operations	21.3	%	5.2	%	10.6	%

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. 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 February 8, 2013 we completed the sale of substantially all the assets of Shrco, formerly included in our Manufacturing segment, for approximately \$13.0 million in cash and received a working capital true up of approximately \$2.4 million in June 2013.

On January 18, 2012, we sold the assets of Aviva, a subsidiary of Shrco, for \$0.3 million in cash. For discontinued operations reporting, Aviva's results are included in Shrco's consolidated results. On November 30, 2012 we completed the sale of the assets of IMD for total proceeds, net of commissions and selling costs, of \$18.1 million. Prior to the sale, IMD was the only remaining entity in our former Wind Energy segment. On February 29, 2012 we completed the sale of DMS, our health services company, for \$24.0 million in cash net of commissions and selling costs, which

was reduced by a \$1.7 million working capital settlement paid to the buyer in February 2013. The DMS working capital settlement was estimated to be \$1.9 million at the time of the sale. The final settlement resulted in recording a \$0.2 million gain on the sale of DMS in the first quarter of 2013. DMS was the only business in our former Health Services segment.

On December 29, 2011 we completed the sale of Wylie for approximately \$25.0 million in cash. Wylie was included in our former Wind Energy segment. On May 6, 2011 we completed the sale of IPH for approximately \$86.0 million in cash. IPH was the only business in our former Food Ingredient Processing segment.

Our Wind Energy, Health Services and Food Ingredient Processing segments were eliminated as a result of the sales of IMD, DMS and IPH. The financial position, results of operations, and cash flows of IMD, Wylie, Shrco, DMS and IPH are reported as discontinued operations in our consolidated financial statements. Following are summary presentations of the results of discontinued operations for the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31, 2013

(in thousands)	IMD	Wylie	Shrco	DMS	IPH	Intercompany Transactions Adjustment	Total
Operating Revenues	\$ --	\$ --	\$ 2,016	\$ --	\$ --	\$ --	\$ 2,016
Operating Expenses	(988)	640	2,622	(269)	--	--	2,005
Other Income	412	--	67	--	--	--	479
Income Tax Expense (Benefit)	370	(256)	(213)	108	--	--	9
Net Income (Loss) from Operations	1,030	(384)	(326)	161	--	--	481
Gain on Disposition Before Taxes	--	--	16	200	--	--	216
Income Tax Expense on Disposition	--	--	6	--	--	--	6
Net Gain on Disposition	--	--	10	200	--	--	210
Net Income (Loss)	\$ 1,030	\$ (384)	\$ (316)	\$ 361	\$ --	\$ --	\$ 691

For the Year Ended December 31, 2012

(in thousands)	IMD	Wylie	Shrco	DMS	IPH	Intercompany Transactions Adjustment	Total
Operating Revenues	\$ 186,151	\$ --	\$ 32,563	\$ 16,362	\$ --	\$ (2,017)	\$ 233,059
Operating Expenses	184,462	179	36,163	14,741	--	(2,017)	233,528
Asset Impairment Charge	45,573	--	7,747	--	--	--	53,320
Other Income	135	--	15	122	--	--	272
Interest Expense	5,787	--	1,553	279	--	(7,444)	175
Income Tax (Benefit) Expense	(15,792)	13	(4,021)	1,734	106	2,978	(14,982)
Net Loss from Operations	(33,744)	(192)	(8,864)	(270)	(106)	4,466	(38,710)
Loss on Disposition Before Taxes	--	(62)	--	(5,154)	--	--	(5,216)
Income Tax Expense (Benefit) on Disposition	--	460	--	(145)	--	--	315
Net Loss on Disposition	--	(522)	--	(5,009)	--	--	(5,531)
Net Loss	\$ (33,744)	\$ (714)	\$ (8,864)	\$ (5,279)	\$ (106)	\$ 4,466	\$ (44,241)

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For the Year Ended December 31, 2011

(in thousands)	IMD	Wylie	Shrco	DMS	IPH	Intercompany Transactions Adjustment	Total
Operating Revenues	\$ 201,921	\$ 49,884	\$ 39,863	\$ 89,558	\$ 28,125	\$ (6,016)	\$ 403,335
Operating Expenses	218,542	55,927	41,478	85,244	24,046	(6,016)	419,221
Asset Impairment Charge	3,142	--	456	56,379	--	--	59,977
Other (Deductions) Income	(46)	18	1	281	(228)	(3)	23
Interest Expense	6,852	709	1,580	1,726	11	(10,636)	242
Income Tax (Benefit) Expense	(4,768)	(2,683)	(1,462)	(16,058)	1,462	4,254	(19,255)
Net (Loss) Income from Operations	(21,893)	(4,051)	(2,188)	(37,452)	2,378	6,379	(56,827)
(Loss) Gain on Disposition Before Taxes	--	(946)	--	--	15,471	--	14,525
Income Tax Expense on Disposition	--	2,854	--	--	2,997	--	5,851
Net (Loss) Gain on Disposition	--	(3,800)	--	--	12,474	--	8,674
Net (Loss) Income	\$ (21,893)	\$ (7,851)	\$ (2,188)	\$ (37,452)	\$ 14,852	\$ 6,379	\$ (48,153)

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, Plastics and Construction 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, aluminum 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, 2013 and December 31, 2012:

		In Use on	Restricted due	Available on	Available on
		December	to	December	December 31,
		31,	Outstanding	31,	December 31,
		2013	Letters of	2013	2012
			Credit		
(in thousands)	Line Limit				
Otter Tail Corporation Credit Agreement	\$150,000	\$ --	\$ 659	\$ 149,341	\$ 149,267
OTP Credit Agreement	170,000	51,195	1,830	116,975	166,811
Total	\$320,000	\$ 51,195	\$ 2,489	\$ 266,316	\$ 316,078

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, 2012 we filed a shelf registration statement with the Securities and Exchange Commission 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 10, 2015. On May 14, 2012, we entered into a Distribution Agreement (the Agreement) with J.P. Morgan Securities (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.

Equity or debt financing will be required in the period 2014 through 2018 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event 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. Also, our operating cash flow 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.

Our common stock dividend payments have exceeded our net income (losses) in four of the last five years. 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 8 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the Board of Directors. On February 3, 2014 our Board of Directors increased the quarterly dividend from \$0.2975 to \$0.3025 per common share.

Cash provided by operating activities from continuing operations was \$150.3 million in 2013 compared with \$169.0 million in 2012. The \$18.7 million decrease in cash provided by operating activities from continuing operations reflects an \$18.7 million decrease in cash provided by changes in accounts payables and other current liabilities between the years.

Cash provided by operating activities from continuing operations was \$169.0 million in 2012 compared with \$93.7 million in 2011. A major contributor to the \$75.3 million increase in cash from operations was a change from cash used for working capital of \$26.3 million in 2011 to \$24.7 million in cash provided from a reduction in working capital in continuing operations. Deferred debits and other assets increased \$25.1 million in 2011 compared to an increase of \$4.8 million in 2012, mainly due to a smaller increase in regulatory assets in 2012 compared with 2011. Net cash provided by discontinued operations of \$64.6 million in 2012 is mainly from the monetization of IMD's working capital in 2012 after IMD's operations were discontinued. The proceeds generated by the monetization of IMD's working capital were used to pay down our line of credit after the line was used to repurchase the Cascade Note and to pay a \$12.5 million repurchase premium to retire the Cascade Note prior to its maturity date.

Net cash used in investing activities of continuing operations was \$162.5 million in 2013 compared to \$111.9 million in 2012. The \$50.6 million increase is mainly due to increases in cash used for capital expenditures of \$47.9 million at OTP and \$2.3 million at Aevenia between the periods. OTP's \$149.5 million in capital expenditures in 2013 includes a significant level of expenditures for the construction of Big Stone Plant's new AQCS and expenditures for the construction of two major CapX2020 transmission line projects, the Fargo–Monticello 345 kiloVolt (kV) Project and the Brookings–Southeast Twin Cities 345 kV Project. Net proceeds from the sale of discontinued operations of \$12.8 million in 2013 reflect \$14.5 million in net proceeds from the sale of the assets of our waterfront equipment manufacturing business less a \$1.7 million working capital settlement paid to the buyer of DMS, which we sold in the first quarter of 2012.

Net cash used in investing activities of continuing operations was \$111.9 million in 2012 compared to \$65.5 million in 2011. The \$46.4 million increase in cash used for investing activities reflects a \$48.4 million increase in cash used for capital expenditures, mainly due to a \$51.8 million increase in capital expenditures at OTP. The increase in cash used for capital expenditures at OTP is mainly related to expenditures for CapX2020 transmission line projects and initial expenditures for Big Stone Plant's new AQCS scheduled for completion in 2015. Net investing cash flows from discontinued operations were \$28.3 million in 2012 compared with \$70.9 million in 2011. Net proceeds from the sales of DMS, IMD and Aviva were \$42.2 million in 2012, compared to net proceeds of \$107.3 million from the sales of IPH and Wylie in 2011. Net cash used in investing activities of discontinued operations of \$13.9 million in 2012 mainly reflects cash used by DMS to purchase assets held under operating leases. Net cash used in investing activities of discontinued operations of \$36.4 million in 2011 mainly reflects 2011 capital expenditures at DMS, Wylie and IMD.

Net cash used in financing activities of continuing operations of \$49.0 million in 2013 includes \$57.6 million used for the November 2013 early retirement of \$47.7 million of our 9.000% Notes due December 15, 2016 and \$43.8 million in common and preferred stock dividend payments, offset by \$51.2 million in proceeds from short term borrowings at OTP to fund its significant level of capital expenditures. On March 1, 2013 OTP used proceeds from a \$40.9 million unsecured term loan to fund the redemption of all \$25.1 million of the then outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds, and to pay off an intercompany note to us that mirrored our \$15.5 million in outstanding cumulative preferred shares, which were also redeemed on March 1, 2013.

Net cash used in financing activities of continuing operations of \$108.1 million in 2012 includes \$62.5 million used for the early retirement of the Cascade Note and \$44.0 million for the payment of dividends on our outstanding common and preferred shares. This compares to \$92.3 million in cash used in the financing activities of our continuing operations in 2011, when we paid out \$43.9 million in dividends. Also in 2011, OTP issued \$140 million in long-term debt and used a portion of the proceeds to retire its \$90 million Senior Notes due December 1, 2011, and to retire early its \$10.4 million in pollution control refunding revenue bonds due December 1, 2012. A portion of the proceeds were also used to pay down OTP's line of credit borrowings which were at \$10.0 million when the debt was issued. We repaid \$86.8 million in short-term borrowings and checks issued in excess of cash in 2011. In 2011, net proceeds of \$84.3 million from the sale of IPH were used to pay down short-term debt.

CAPITAL REQUIREMENTS

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 \$164 million in 2013, \$116 million in 2012 and \$67 million in 2011. Estimated capital expenditures for 2014 are \$195 million. Total capital expenditures for the five-year period 2014 through 2018 are estimated to be approximately \$769 million, which includes \$131 million for OTP's share of the new AQCS at Big Stone Plant and \$304 million for transmission projects including \$243 million for MVPs and \$26 million for CapX2020 transmission projects (\$7 million for the Brookings to Southeast Twin Cities CapX2020 MVP project is included with the \$243 million for MVP projects).

The breakdown of 2011, 2012 and 2013 actual cash used for capital expenditures and 2014 through 2018 estimated capital expenditures by segment is as follows:

(in millions)	2011	2012	2013	2014	2015	2016	2017	2018	Total for 2014-2018
Electric	\$ 50	\$ 102	\$ 149	\$ 172	\$ 145	\$ 141	\$ 97	\$ 102	\$ 657
Manufacturing	10	9	7	17	12	20	15	17	81
Plastics	2	3	3	4	3	3	2	2	14
Construction	3	2	5	2	4	3	3	5	17
Corporate	2	--	--	--	--	--	--	--	--
Total	\$ 67	\$ 116	\$ 164	\$ 195	\$ 164	\$ 167	\$ 117	\$ 126	\$ 769

The following table summarizes our contractual obligations at December 31, 2013 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)	\$ 761	\$ 50	\$ 42	\$ 47	\$ 622
Debt Obligations	441	92	53	33	263
Capacity and Energy Requirements	347	23	53	48	223
Interest on Debt Obligations	202	21	42	30	109
Other Purchase Obligations	108	85	23	--	--
Postretirement Benefit Obligations	74	4	8	9	53
Operating Lease Obligations	37	8	11	6	12
	\$ 1,970	\$ 283	\$ 232	\$ 173	\$ 1,282

Total Contractual Cash
Obligations

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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.

On February 27, 2014 OTP issued, 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 2029 Notes) and \$90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the 2044 Notes and, together with the 2029 Notes, the New OTP Notes). OTP used a portion of the proceeds of the Notes to retire early its \$40.9 million term loan, due January 15, 2015 and to repay outstanding short-term debt. The remaining proceeds of the New OTP Notes will be used to repay additional short-term debt of OTP, to pay fees and expenses related to the issuance of the New OTP Notes and for other general corporate purposes, including planned construction program expenditures.

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 2014 through 2018 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

On May 11, 2012 we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement.

On May 14, 2012, we entered into the Agreement with JPMS. Pursuant to the terms of the Agreement, we may offer and sell our common shares from time to time through JPMS, as our distribution agent for the offer and sale of the shares, up to an aggregate sales price of \$75 million. Under the Agreement, 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. The shares, if issued, will be issued pursuant to our shelf registration statement, as amended. No shares have been sold pursuant to the Agreement.

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2013 and December 31, 2012:

(in thousands)	Line Limit	In Use on December 31, 2013	Restricted due to Outstanding Letters of	Available on December 31, 2013	Available on December 31, 2012
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Credit

Otter Tail Corporation Credit					
Agreement	\$ 150,000	\$ --	\$ 659	\$ 149,341	\$ 149,267
OTP Credit Agreement	170,000	51,195	1,830	116,975	166,811
Total	\$ 320,000	\$ 51,195	\$ 2,489	\$ 266,316	\$ 316,078

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2013 was \$4,754,000 on December 2, 2013 and the average daily balance of debt outstanding during 2013 was \$49,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2013 was 1.9% compared with 3.8% in 2012. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2013 was \$53,003,000 on December 13, 2013 and the average daily balance of debt outstanding during 2013 was \$17,446,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2013 was 1.4% compared with 1.7% in 2012. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2013 was 1.4%.

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured \$150 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 29, 2013 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2017 to October 29, 2018. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on our senior unsecured credit ratings. The interest rate being charged under the Second Amended and Restated Credit Agreement prior to the renewal was LIBOR plus 3.25%. 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 Varistar and its material 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 material subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to \$40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured \$170 million revolving credit facility that may be increased to \$250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 29, 2013 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2017 to October 29, 2018. 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. 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

Debt Retirements

On November 6 and 25, 2013 we purchased, in two separate transactions, \$12,933,000 and \$34,737,000, respectively, of our outstanding 9.000% notes due 2016 (the 2016 Notes), originally issued in the aggregate principal amount of \$100 million. The purchased 2016 Notes (the Purchased 2016 Notes) were subsequently retired and are no longer outstanding. The remaining \$52,330,000 principal amount of 2016 Notes outstanding, unless redeemed early or otherwise repaid, will mature and become due and payable on December 15, 2016. The price paid for the Purchased 2016 Notes was \$59,404,000, which includes the principal amount of the Purchased 2016 Notes, plus accrued interest of \$1,845,000 through the respective purchase dates and a negotiated premium of \$9,889,000 (which is less than the premium we would have been required to pay to redeem them under the terms of the 2016 Notes). We used cash on

hand to fund the purchase of the Purchased 2016 Notes. The amount of the debt retired as a result of these transactions is approximately equivalent to the remaining amount of debt that was associated with the operating companies that we have divested over the last two years. The retirement of the Purchased Notes further strengthens our capital structure and reduces our pre-tax interest expense by approximately \$4.3 million in both 2014 and 2015 and \$4.1 million in 2016. On repayment, \$363,000 in unamortized debt expense related to the 2016 Notes was immediately recognized as expense along with the \$9,889,000 negotiated premium which, in total, reduced diluted earnings per share by \$0.17 in 2013.

On July 13, 2012 we prepaid in full the Cascade Note issued pursuant to the Note Purchase Agreement dated as of February 23, 2007, as amended, between us and Cascade Investment L.L.C. (Cascade). Immediately before the prepayment, the Cascade Note bore interest at 8.89% annually. The price paid by us to prepay the Cascade Note was \$63,031,000, which included the principal amount of the Cascade Note plus accrued interest of \$531,000 and a negotiated prepayment premium of \$12,500,000. We used the funds available under the Otter Tail Corporation Credit Agreement for the prepayment. This early retirement reflected our desire to lower our long-term debt outstanding given our recent divestitures. This retirement of debt strengthens our consolidated capital structure and will positively affect future years' earnings by lowering interest costs. On repayment, \$606,000 in unamortized debt expense related to this note was immediately recognized as expense along with the \$12,500,000 negotiated prepayment premium, which, in total, reduced diluted earnings per share by \$0.22 in 2012. Cascade owned approximately 9.5% of our outstanding common stock as of December 31, 2013.

In addition, on February 27, 2014 the Company repaid in full its Term Loan as described below.

Unsecured Term Loan due January 15, 2015

On March 1, 2013 OTP entered into a Credit Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan) providing for a \$40.9 million unsecured term loan (the Term Loan) to OTP originally due on June 1, 2014, which was fully drawn on March 1, 2013. The Loan Agreement was amended on October 29, 2013 to extend the due date on the Term Loan to January 15, 2015. On February 27, 2014 OTP used a portion of the proceeds of the New OTP Notes described below to retire early the Term Loan.

Borrowings under the Loan Agreement bore interest at LIBOR plus 0.875%. On March 1, 2013 OTP utilized approximately \$25.1 million of Term Loan proceeds to fund the redemption price for all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on that date, in each case for which OTP paid debt service. All such bonds had been called for redemption in full on March 1, 2013. Also on March 1, 2013, OTP utilized approximately \$15.7 million of Term Loan proceeds to satisfy an intercompany note to us that had a balance and interest rate designed to equate to the balances and dividend rates of our cumulative preferred shares. Those cumulative preferred shares were redeemed on March 1, 2013 for \$15.7 million, including \$0.2 million in call premiums charged to equity and included with preferred dividends paid and as part of our preferred dividend requirement for the year ended December 31, 2013.

2016 Notes

On December 4, 2009 we issued \$100 million of our 9.000% notes due 2016 (the 2016 Notes) under the indenture (for unsecured debt securities) dated as of November 1, 1997, as amended by the First Supplemental Indenture dated as of July 1, 2009, between us and U.S. Bank National Association (formerly First Trust National Association), as trustee. The 2016 Notes are senior unsecured indebtedness and bear interest at 9.000% per year, payable semi-annually in arrears on June 15 and December 15 of each year. In November 2013 we purchased and retired, in two separate transactions, \$12,933,000 and \$34,737,000, respectively, of our outstanding 2016 Notes. The remaining \$52,330,000 principal amount of the 2016 Notes outstanding, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) pursuant to which OTP agreed to issue the New OTP Notes to the purchasers named therein, in a private placement transaction. On February 27, 2014 OTP issued the New OTP Notes. OTP used a portion of the proceeds of the New OTP Notes to

retire early the Term Loan as discussed above and to repay OTP's short-term debt outstanding on February 27, 2014. The remaining proceeds of the New OTP Notes will be used to pay fees and expenses related to the issuance of the New OTP Notes and for other general purposes, including planned construction program expenditures.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the New OTP Notes (in an amount not less than 10% of the aggregate principal amount of the New OTP 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 2029 Notes then outstanding on or after November 27, 2028 or (ii) all of the 2044 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 New OTP Notes at 100% of the principal amount together with unpaid accrued interest in the event of a change of control 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 OTP's existing 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 New OTP Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued \$140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes) pursuant to a Note Purchase Agreement dated as of July 29, 2011 (2011 Note Purchase Agreement). OTP used a portion of the proceeds of the 2021 Notes to retire \$90 million aggregate principal amount of OTP's 6.63% Senior Notes due December 1, 2011 at maturity and to retire early \$10.4 million aggregate principal amount of outstanding pollution control refunding revenue bonds due December 1, 2012. No penalty was paid for the early retirement. The remaining proceeds of the 2021 Notes were used to repay short-term debt of OTP which was issued to fund capital expenditures, to pay fees and expenses related to the debt issuance and to fund a \$10 million contribution to the Company's pension plan in January 2012.

OTP also has outstanding its \$155 million senior unsecured notes issued in four series consisting of \$33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; \$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).

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."

PACE Loan

On March 18, 2011 we borrowed \$1.5 million under a Partnership in Assisting Community Expansion loan to finance capital investments at Northern Pipe Products, Inc. (Northern Pipe), the Company's PVC pipe manufacturing subsidiary located in Fargo, North Dakota. The ten-year unsecured note bears interest at 2.54% with monthly principal and interest payments through March 2021. On April 6, 2011 we borrowed \$0.5 million under a North Dakota Development Fund loan to finance additional capital investments at Northern Pipe. The seven-year unsecured note bears interest at 3.95% with monthly principal and interest payments through April 1, 2018.

Financial Covenants

We were in compliance with the financial covenants in our debt agreements as of December 31, 2013.

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, 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 provided in the Otter Tail Corporation Credit Agreement. As of December 31, 2013 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement was 3.85 to 1.00.

Under the OTP Credit Agreement and the Loan Agreement (when in effect), 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, 2013 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 3.72 to 1.00.

Under the 2013 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, each as provided in the 2013 Note Purchase Agreement.

As of December 31, 2013 our interest-bearing debt to total capitalization was 0.45 to 1.00 on a consolidated basis and 0.50 to 1.00 for OTP.

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 3.4x for 2013 compared to 2.6x for 2012. Our debt interest coverage ratio before taxes, calculated by dividing income before income taxes from continuing operation plus interest charges by interest charges plus capitalized interest, was 3.2x for 2013 compared to 2.2x for 2012. During 2014, we expect these coverage ratios to increase, assuming 2014 net income meets our expectations.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling \$9.0 million, but our line of credit borrowing limits are only restricted by \$2.5 million of the 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.

2014 BUSINESS OUTLOOK

We anticipate 2014 diluted earnings per share to be in the range of \$1.55 to \$1.75. This guidance reflects the current mix of businesses owned by us. It considers the cyclical nature of some of our businesses and reflects challenges, as well as our plans and strategies for improving future operating results. We expect capital expenditures for 2014 to be \$195 million compared with \$164 million in 2013. Major projects contributing to the increase in planned expenditures are the new AQCS under construction at Big Stone Plant and investments in several transmission projects for the Electric segment, including CapX2020 and MISO-designated Multi-Value projects that are expected to positively impact our earnings and provide an immediate return on capital.

Segment components of our 2014 earnings per share guidance range are as follows:

	2013 EPS by Segment	2014 EPS Guidance	
		Low	High
Electric	\$1.05	\$1.19	\$1.23
Manufacturing	\$0.32	\$0.29	\$0.33
Plastics	\$0.38	\$0.25	\$0.29
Construction	\$0.04	\$0.07	\$0.11
Corporate	(\$0.25)	(\$0.25)	(\$0.21)
Subtotal – Continuing Operations	\$1.54	\$1.55	\$1.75
Corporate – Loss on Debt Extinguishment	(\$0.17)		
Total – Continuing Operations	\$1.37	\$1.55	\$1.75

Contributing to our earnings guidance for 2014 are the following items:

We expect net income to increase significantly in our Electric segment in 2014 compared with 2013 based on the following items:

- o Rider recovery increases, including environmental riders in Minnesota and North Dakota related to the Big Stone AQCS environmental upgrades while under construction, and
- o A decrease in pension costs of approximately \$2.0 million as a result of an increase in the discount rate from 4.5% to 5.3%, offset by
- o An increase in interest costs as a result of \$150 million of fixed rate long term debt being put in place in the first quarter of 2014 to finance the Big Stone Plant AQCS and transmission projects, and
- o An increase in operating and maintenance costs primarily for increased labor and a planned outage for maintenance at Hoot Lake Plant.

We expect net income from our Manufacturing segment to be flat between the years due to the following factors:

- o An increase at BTD due to increased order volume as a result of expanded relationships with customers in recreational vehicle, lawn and garden, industrial and commercial end markets BTD serves, offset by
- o

A decrease in earnings from T.O. Plastics due to a reduction in sales of a product the customer will be producing on its own in 2014.

oBacklog for the manufacturing companies of approximately \$136 million for 2014 compared with \$124 million one year ago.

We expect net income in our Plastics segment to return to more normal levels in 2014 compared with 2013. The Plastics segment experienced its fourth best earnings year in its history in 2013 due to increased sales volumes in construction and housing markets in the South Central and Southwest regions of the United States and high levels of construction activity in the North Central United States. Gross margins are expected to return to more normal levels in 2014 compared with 2013. Secondly, sales volumes and sales prices are currently expected to be slightly lower in 2014 compared to 2013.

We expect higher net income from our Construction segment in 2014 as a result of improved cost control processes in construction management and more selective bidding on projects with the potential for higher margins. Backlog in place for the construction businesses is \$77 million for 2014 compared with \$151 million one year ago.

Corporate costs are expected to be down in 2014 due to lower interest costs as a result of retiring \$47.7 million of 9% long term debt in the fourth quarter of 2013, offset by general inflation increases in labor, benefits and other general and administrative costs.

We review our portfolio of companies annually to see where additional opportunities exist to improve our risk profile, improve credit metrics and generate additional sources of cash to support the future capital expenditure plans of our Electric segment.

The following table shows our 2013 capital expenditures and 2014 through 2018 anticipated capital expenditures and electric utility average rate base:

(in millions)	2013	2014	2015	2016	2017	2018
Capital Expenditures:						
Electric Segment:						
Transmission		\$53	\$46	\$97	\$52	\$56
Environmental		82	61	--	--	--
Other		37	38	44	45	46
Total Electric Segment	\$149	\$172	\$145	\$141	\$97	\$102
Manufacturing and Infrastructure Segments	15	23	19	26	20	24
Total Capital Expenditures	\$164	\$195	\$164	\$167	\$117	\$126
Total Electric Utility Average Rate Base		\$885	\$991	\$1,062	\$1,120	\$1,152

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 2014 through 2018 timeframe.

Our outlook for 2014 is dependent on a variety of factors and is subject to the risks and uncertainties discussed in Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

Our significant accounting policies are described in note 1 to 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, accrued renewable resource, transmission, and environmental cost recovery rider revenues, valuations of forward energy contracts, percentage-of-completion, warranty 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 12 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 40 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 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 2014 for our noncontributory funded pension plan is expected to be \$4.9 million compared to \$10.3 million in 2013, reflecting no change in the assumed rate of return on pension plan assets from 7.75% in 2013, and an increase in the estimated discount rate used to determine annual benefit cost accruals from 4.50% in 2013 to 5.30% in 2014. 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 plans 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 2013, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2013 pension benefit cost by \$806,000; a 0.25 decrease in the discount rate would have increased our 2013 pension benefit cost by \$846,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2013 pension benefit cost by \$515,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2013 pension benefit cost by \$503,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2013 pension benefit cost by \$468,000.

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 2013 postretirement medical benefit costs by \$270,000. A 0.25 decrease in the discount rate would have increased our 2013 postretirement medical benefit costs by \$284,000. See note 12 to our 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.

REVENUE RECOGNITION

Our construction companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of costs incurred to total estimated costs. The duration of the majority of these contracts ranges from less than a year up to three years. Revenues recognized on jobs in progress as of December 31, 2013 were \$368 million. Any expected losses on jobs in progress at year-end 2013 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

We have a standard quarterly estimate at completion process in which we review the progress and performance of our contracts accounted for under percentage-of-completion accounting. As part of this process, our reviews include, but are not limited to, any outstanding key contract matters, progress towards completion and the related program schedule, identified risks and opportunities, and the related changes in estimates of revenues and costs. The risks and opportunities include our judgment about the ability and cost to achieve the schedule, technical requirements and other contract requirements. We must make assumptions regarding labor productivity and availability, the complexity of the work to be performed, the availability of materials, the length of time to complete the contract, and performance by subcontractors, among other variables. Based on this analysis, any adjustments to net sales, costs of sales, and the related impact to operating income are recorded as necessary in the period they become known. These adjustments may result from positive program performance and an increase in operating profit during the performance of

individual contracts if we determine we will be successful in mitigating risks surrounding the technical, schedule, and cost aspects of those contracts or realizing related opportunities. Likewise, these adjustments may result in a decrease in operating profit if we determine we will not be successful in mitigating these risks or realizing related opportunities. Changes in estimates of net sales, costs of sales, and the related impact to operating income are recognized using a cumulative catch-up, which recognizes, in the current period, the cumulative effect of the changes on current and prior periods based on a contract's percent complete. A significant change in one or more of these estimates could affect the profitability of one or more of our contracts. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

OTP's forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under generally accepted accounting principles. Market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models, and as such, are estimates. The forward energy purchase contracts that are marked to market as of December 31, 2013 are 100% offset by forward energy sales contracts in terms of volumes and delivery periods but not in terms of delivery points. The differential in forward prices entered into with different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy contracts of \$115,000.

OTP's recognized but unrealized net gains of \$115,000 on forward purchases and sales of electricity marked to market on December 31, 2013 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

	1st
(in	Quarter
thousands)	2014
Net Gain	\$ 115

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Our operating companies encounter risks associated with sales and the collection of the associated accounts receivable. As such, they record provisions for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, the operating companies primarily utilize historical rates of accounts receivables written off as a percentage of total revenue. This historical rate is applied to the current revenues on a monthly basis. The historical rate is updated periodically based on events that may change the rate, such as a significant increase or decrease in collection performance and timing of payments as well as the calculated total exposure in relation to the allowance. Periodically, operating companies compare identified credit risks with allowances that have been established using historical experience and adjust allowances accordingly. In circumstances where an operating company is aware of a specific customer's inability to meet financial obligations, the operating company records a specific allowance for bad debts to reduce the account receivable to the amount it reasonably believes will be collected.

We believe the accounting estimates related to the allowance for doubtful accounts is critical because the underlying assumptions used for the allowance can change from period to period and could potentially cause a material impact to the income statement and working capital.

During 2013, for continuing operations, \$1,017,000 of bad debt expense (0.1% of total 2013 revenue of \$893.3 million) was recorded and the allowance for doubtful accounts was \$1.2 million (1.4% of gross trade accounts receivable) as of December 31, 2013. General economic conditions and specific geographic concerns are major factors that may affect the adequacy of the allowance and may result in a change in the annual bad debt expense. An increase or decrease in our consolidated allowance for doubtful accounts based on one percentage point of outstanding trade receivables at December 31, 2013 would result in a \$0.8 million increase or decrease in bad debt expense.

Although an estimated allowance for doubtful accounts on our operating companies' accounts receivable is provided for, the allowance for doubtful accounts on the Electric segment's wholesale electric sales is insignificant in proportion to annual revenues from these sales. The Electric segment has not experienced a bad debt related to wholesale electric sales largely due to stringent risk management criteria related to these sales. Nonpayment on a single wholesale electric sale could result in a significant bad debt expense.

DEPRECIATION EXPENSE AND DEPRECIABLE LIVES

The provisions for depreciation of electric utility property for financial reporting purposes are made on the straight-line method based on the estimated service lives (5 to 70 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.96% in 2013, 2.98% in 2012 and 2.94% in 2011. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

Property and equipment of our nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting and are depreciated on a straight-line basis over useful lives (3 to 40 years) of the related assets. We believe the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries in which our manufacturing and infrastructure companies operate or innovations in technology could result in a reduction of the estimated useful lives of our manufacturing and infrastructure operating companies' property, plant and equipment or in an impairment write-down of the carrying value of these properties.

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, 2013 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of Accounting Standards Codification (ASC) 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 both 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 they are highly susceptible to change from period to period reflecting changing business cycles and require management to make assumptions about

future cash flows over future years and 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.

In 2012, asset impairments were recorded at IMD, Shrco and OTESCO. The IMD and Shrco impairments were recorded in connection with their sales value and are reflected in the results of discontinued operations. As of December 31, 2013 an assessment of the carrying amounts of our remaining 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 quantitative goodwill impairment testing annually in the fourth quarter. In addition, the test 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.

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 of our 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, 2013, the fair value substantially exceeded the carrying value at all our reporting units.

Determining the fair value of a reporting unit 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. 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 an impairment is indicated.

We currently have \$7.3 million of goodwill and a \$1.1 million indefinite-lived trade name recorded on our balance sheet related to the acquisition of Foley in 2003. Foley's net earnings improved \$10.4 million between 2012 and 2013. If operating profits do not meet our projections, the reductions in anticipated cash flows from Foley may indicate that its fair value is less than its book value, resulting in an impairment of some or all of the goodwill and indefinite-lived intangible assets associated with Foley along with a corresponding charge against earnings.

An assessment of the carrying amounts of our goodwill as of December 31, 2013 indicated the fair values of our reporting units are substantially in excess of their respective book values and not impaired.

ACQUISITION METHOD OF ACCOUNTING

We account for acquisitions under the requirements of ASC Topic 805, Business Combinations. Under ASC 805 the term “purchase method of accounting” is replaced with “acquisition method of accounting” and requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions.

Acquired assets and liabilities assumed that are subject to critical estimates include property, plant and equipment and intangible assets. The fair value of property, plant and equipment is based on valuations performed by qualified internal personnel and/or with the assistance of outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase. Intangible assets are identified and valued using the guidelines of ASC 805. The fair value of intangible assets is based on estimates including royalty rates, customer attrition rates and estimated cash flows.

While the allocation of purchase price is subject to a high degree of judgment and uncertainty, we do not expect the estimates to vary significantly once an acquisition is complete. We believe our estimates have been reasonable in the past as there have been no significant valuation adjustments to the allocation of purchase price.

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, 2013 we had exposure to market risk associated with interest rates because we had \$51.2 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 1.25% under OTP's \$170 million revolving credit facility.

The majority of our consolidated long-term debt 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. As of December 31, 2013 we had \$40.9 million of long-term debt outstanding under an unsecured term loan subject to a variable interest rate of LIBOR plus 0.875%. This debt was early retired on February 27, 2014 with proceeds from the issuance of fixed-rate debt (see discussion under "Management's Discussion and Analysis of Financial Conditions and Results of Operations – Capital Resources" on page 54 of this Annual Report on Form 10-K).

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 (PS) 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.

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2013 OTP had recognized, on a pretax basis, \$115,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid

can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy purchase contracts that are marked to market as of December 31, 2013, are 100% offset by forward energy sales contracts in terms of volumes and delivery periods but not in terms of delivery points. The differential in forward prices entered into with different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy contracts of \$115,000.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with our energy trading activities. Additionally, we have a Value at Risk (VaR) limit to further manage market price risk. There was price risk on open positions as of December 31, 2013 where purchases were not at the same delivery points as the offsetting sales.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of December 31, 2013 and December 31, 2012, and the change in the Company's consolidated balance sheet position from December 31, 2012 to December 31, 2013 and December 31, 2011 to December 31, 2012:

(in thousands)	December 31, 2013	December 31, 2012
Current Asset – Marked-to-Market Gain	\$ 338	\$ 502
Regulatory Asset – Current Deferred Marked-to-Market Loss	3,008	7,949
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	8,674	10,050
Total Assets	12,020	18,501
Current Liability – Marked-to-Market Loss	(11,782)	(18,234)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(6)	(8)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(117)	(210)
Total Liabilities	(11,905)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	\$ 115	\$ 49

(in thousands)	Year ended December 31, 2013	Year ended December 31, 2012
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	\$ 49	\$ 894
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(49)	(861)
Changes in Fair Value of Contracts Entered into in Prior Periods	--	(33)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	--
Changes in Fair Value of Contracts Entered into in Current Period	115	49
Cumulative Fair Value Adjustments Included in Earnings - End of Period	\$ 115	\$ 49

The \$115,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2013 is expected to be realized on settlement in the first quarter of 2014.

The following realized and unrealized net gains (losses) on forward energy contracts are included in electric operating revenues on our consolidated statements of income:

(in thousands)	2013	Year Ended December 31, 2012	2011
Net Gains (Losses) on Forward Electric Energy Contracts	\$ 432	\$ (61)	\$ 926

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2013 was \$530,000. As of December 31, 2013 OTP had a net credit risk exposure of \$856,000 from three counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2013 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The \$856,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains on forward contracts for the purchase of gasoline scheduled for settlement subsequent December 31, 2013. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders of
Otter Tail Corporation

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and its subsidiaries (the “Company”) as of December 31, 2013 and 2012, 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, 2013. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company’s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for these financial statements and financial statement schedule, 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 financial statement schedule and an opinion on the Company’s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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, 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.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or

detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Otter Tail Corporation and its subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
March 3, 2014

OTTER TAIL CORPORATION

Consolidated Balance Sheets, December 31

(in thousands)

	2013	2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	\$1,150	\$52,362
Accounts Receivable:		
Trade (less allowance for doubtful accounts of \$1,177 for 2013 and \$1,279 for 2012)	83,572	91,170
Other	9,790	7,684
Inventories	72,681	69,336
Deferred Income Taxes	35,452	30,964
Unbilled Revenues	18,157	15,701
Costs and Estimated Earnings in Excess of Billings	4,063	3,663
Regulatory Assets	17,940	25,499
Other	7,747	8,161
Assets of Discontinued Operations	38	19,092
Total Current Assets	250,590	323,632
Investments	9,362	9,471
Other Assets	28,834	26,222
Goodwill	38,971	38,971
Other Intangibles--Net	13,328	14,305
Deferred Debits		
Unamortized Debt Expense	4,188	5,529
Regulatory Assets	83,730	134,755
Total Deferred Debits	87,918	140,284
Plant		
Electric Plant in Service	1,460,884	1,423,303
Nonelectric Operations	194,872	186,094
Construction Work in Progress	187,461	77,890
Total Gross Plant	1,843,217	1,687,287
Less Accumulated Depreciation and Amortization	676,201	637,835
Net Plant	1,167,016	1,049,452
Total Assets	\$1,596,019	\$1,602,337

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

Consolidated Balance Sheets, December 31

(in thousands, except share data)

	2013	2012
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	\$51,195	\$--
Current Maturities of Long-Term Debt	188	176
Accounts Payable	113,457	88,406
Accrued Salaries and Wages	19,903	20,571
Billings In Excess Of Costs and Estimated Earnings	13,707	16,204
Accrued Taxes	12,491	12,047
Derivative Liabilities	11,782	18,234
Other Accrued Liabilities	6,532	6,334
Liabilities of Discontinued Operations	3,637	11,156
Total Current Liabilities	232,892	173,128
Pensions Benefit Liability	69,743	116,541
Other Postretirement Benefits Liability	45,221	58,883
Other Noncurrent Liabilities	25,209	22,244
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	195,603	171,787
Deferred Tax Credits	28,288	31,299
Regulatory Liabilities	73,926	68,835
Other	718	466
Total Deferred Credits	298,535	272,387
Capitalization (page 74)		
Long-Term Debt, Net of Current Maturities	389,589	421,680
Cumulative Preferred Shares		
Authorized 1,500,000 Shares Without Par Value;		
Outstanding 2013—None; 2012—155,000 Shares	--	15,500
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, 2013—36,271,696 Shares; 2012—36,168,368 Shares	181,358	180,842
Premium on Common Shares	255,759	253,296
Retained Earnings	99,441	92,221
Accumulated Other Comprehensive Loss	(1,728)	(4,385)
Total Common Equity	534,830	521,974

Total Capitalization	924,419	959,154
Total Liabilities and Equity	\$1,596,019	\$1,602,337

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

Consolidated Statements of Income--For the Years Ended December 31

(in thousands, except per-share amounts)

	2013	2012	2011
Operating Revenues			
Electric	\$373,459	\$350,679	\$342,633
Product Sales	369,952	359,474	313,020
Construction Services	149,902	149,086	184,516
Total Operating Revenues	893,313	859,239	840,169
Operating Expenses			
Production Fuel - Electric	71,248	66,284	69,017
Purchased Power - Electric System Use	52,006	49,184	43,451
Electric Operation and Maintenance Expenses	133,395	121,069	115,863
Cost of Products Sold (depreciation included below)	283,260	270,041	248,021
Cost of Construction Revenues Earned (depreciation included below)	133,427	147,097	173,629
Other Nonelectric Expenses	51,930	52,621	49,296
Asset Impairment Charge	--	432	470
Depreciation and Amortization	59,885	59,764	58,335
Property Taxes - Electric	11,311	10,720	10,190
Total Operating Expenses	796,462	777,212	768,272
Operating Income	96,851	82,027	71,897
Interest Charges	26,978	31,905	35,629
Loss on Early Retirement of Debt	10,252	13,106	--
Other Income	4,096	4,085	2,763
Income Before Income Taxes – Continuing Operations	63,717	41,101	39,031
Income Tax Expense – Continuing Operations	13,543	2,133	4,121
Net Income from Continuing Operations	50,174	38,968	34,910
Discontinued Operations			
Income (Loss) - net of Income Tax Expense (Benefit) of \$9 in 2013, \$6,231 in 2012 and (\$1,811) in 2011	481	(6,603)	(14,294)
Impairment Loss - net of Income Tax (Benefit) of (\$21,213) in 2012 and (\$17,444) in 2011	--	(32,107)	(42,533)
Gain (Loss) on Disposition - net of Income Tax Expense of \$6 in 2013, \$315 in 2012 and \$5,851 in 2011	210	(5,531)	8,674
Net Gain (Loss) from Discontinued Operations	691	(44,241)	(48,153)
Total Net Income (Loss)	50,865	(5,273)	(13,243)
Preferred Dividend Requirement and Other Adjustments	513	736	1,058
Earnings (Loss) Available for Common Shares	\$50,352	\$ (6,009)	\$ (14,301)
Average Number of Common Shares Outstanding--Basic	36,151	36,048	35,922
Average Number of Common Shares Outstanding--Diluted	36,355	36,242	36,082
Basic Earnings (Loss) Per Common Share:			
Continuing Operations (net of preferred dividend requirement)	\$ 1.37	\$ 1.06	\$ 0.95

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Discontinued Operations	\$0.02	\$(1.23	) \$(1.35	)
	\$1.39	\$(0.17	) \$(0.40	)
Diluted Earnings (Loss) Per Common Share:				
Continuing Operations (net of preferred dividend requirement)	\$1.37	\$1.05	\$0.95	
Discontinued Operations	\$0.02	\$(1.22	) \$(1.35	)
	\$1.39	\$(0.17	) \$(0.40	)
Dividends Declared Per Common Share	\$1.19	\$1.19	\$1.19	

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

Consolidated Statements of Comprehensive Income--For the Years Ended December 31

(in thousands)	2013	2012	2011
Net Income (Loss)	\$50,865	\$(5,273)	\$(13,243)
Other Comprehensive Income (Loss):			
Unrealized (Loss) Gain on Available-for-Sale Securities:			
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	(27)	--	--
(Losses) Gains Arising During Period	(77)	154	(121)
Income Tax Benefit (Expense)	36	(53)	48
Change in Unrealized Gains on Available-for-Sale Securities – net-of-tax	(68)	101	(73)
Reversal of Foreign Currency Translation Adjustment Unrealized Gain:			
Unrealized Net Change During Period	--	--	303
Reversal of Previously Recognized Gains Realized on Sale of IPH in 2011	--	--	(6,068)
Income Tax Benefit	--	--	1,787
Reversal of Foreign Currency Translation Adjustment Unrealized Gain – net-of-tax	--	--	(3,978)
Pension and Postretirement Benefit Plans:			
Actuarial Gains (Losses) Net of Regulatory Allocation Adjustment	3,986	(2,133)	(1,686)
Amortization of Unrecognized Postretirement Benefit Costs (note 12)	555	376	239
Income Tax (Expense) Benefit	(1,816)	703	579
Pension and Postretirement Benefit Plans – net-of-tax	2,725	(1,054)	(868)
 Total Other Comprehensive Income (Loss)	 2,657	 (953)	 (4,919)
 Total Comprehensive Income (Loss)	 \$53,522	 \$(6,226)	 \$(18,162)

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

Consolidated Statements of Common Shareholders' Equity

	Common Shares	Par Value, Common Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
(in thousands, except common shares outstanding)	Outstanding					
Balance, December 31, 2010	36,002,739	\$180,014	\$251,919	\$198,443	\$1,487	\$631,863
Common Stock Issuances, Net of Expenses	154,225	771	2,671			3,442
Common Stock Retirements	(55,269)	(276)	(906)			(1,182)
Net Loss				(13,243)		(13,243)
Other Comprehensive Loss					(4,919)	(4,919)
Tax Benefit – Stock Compensation			(875)			(875)
Employee Stock Incentive Plan Expense			606			606
Premium on Purchase of Stock for Employee Purchase Plan			(292)			(292)
Premium on Purchase of Subsidiary Class B Stock and Options				(322)		(322)
Cumulative Preferred Dividends				(735)		(735)
Common Dividends (\$1.19 per share)				(42,895)		(42,895)
Balance, December 31, 2011	36,101,695	\$180,509	\$253,123	\$141,248	\$(3,432)(a)	\$571,448
Common Stock Issuances, Net of Expenses	71,745	359	148			507
Common Stock Retirements	(5,072)	(26)	(85)			(111)
Net Loss				(5,273)		(5,273)
Other Comprehensive Loss					(953)	(953)
Tax Benefit – Stock Compensation			(103)			(103)
Employee Stock Incentive Plan Expense			435			435
Premium on Purchase of Stock for Employee Purchase Plan			(222)			(222)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends (\$1.19 per share)				(43,018)		(43,018)
Balance, December 31, 2012	36,168,368	\$180,842	\$253,296	\$92,221	\$(4,385)(a)	\$521,974
Common Stock Issuances, Net of Expenses	112,512	562	2,095			2,657
Common Stock Retirements	(9,184)	(46)	(177)			(223)
Net Income				50,865		50,865
Other Comprehensive Income					2,657	2,657
Tax Benefit – Stock Compensation			299			299
Employee Stock Incentive Plan Expense			418			418
Premium on Purchase of Stock for Employee Purchase Plan			(258)			(258)
Cumulative Preferred Dividends				(427)		(427)
Preferred Stock Issuance Expenses Transferred to Retained Earnings on Redemption of Preferred Shares			86	(86)		--
Common Dividends (\$1.19 per share)				(43,132)		(43,132)
Balance, December 31, 2013	36,271,696	\$181,358	\$255,759	\$99,441	\$(1,728)(a)	\$534,830

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

(in thousands)	2013	2012	2011
Unrealized Gain on Marketable Equity Securities:			
Before Tax	\$73	\$177	\$23
Tax Effect	(26)	(62)	(9)
Unrealized Gain on Marketable Equity Securities – Net-of-Tax	47	115	14
Unamortized Actuarial Losses, Prior Service Costs and Transition Obligation Related to Pension and Postretirement Benefits:			
Before Tax	(2,959)	(7,500)	(5,743)
Tax Effect	1,184	3,000	2,297
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits – Net-of-Tax	(1,775)	(4,500)	(3,446)
Accumulated Other Comprehensive Loss:			
Before Tax	(2,886)	(7,323)	(5,720)
Tax Effect	1,158	2,938	2,288
Net Accumulated Other Comprehensive Loss	\$(1,728)	\$(4,385)	\$(3,432)

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

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

(in thousands)	2013	2012	2011
Cash Flows from Operating Activities			
Net Income (Loss)	\$50,865	\$(5,273)	\$(13,243)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Net (Gain) Loss from Sale of Discontinued Operations	(210)	5,531	(8,674)
Net (Income) Loss from Discontinued Operations	(481)	38,710	56,827
Depreciation and Amortization	59,885	59,764	58,335
Asset Impairment Charge	--	432	470
Premium Paid for Early Retirement of Long-Term Debt	9,889	12,500	--
Deferred Tax Credits	(1,925)	(2,091)	(2,386)
Deferred Income Taxes	15,902	11,459	10,661
Change in Deferred Debits and Other Assets	56,720	(4,802)	(25,053)
Discretionary Contribution to Pension Fund	(10,000)	(10,000)	--
Change in Noncurrent Liabilities and Deferred Credits	(42,226)	32,718	35,178
Allowance for Equity/Other Funds Used During Construction	(1,823)	(1,168)	(861)
Change in Derivatives Net of Regulatory Deferral	8	718	72
Stock Compensation Expense – Equity Awards	1,456	1,311	2,177
Other—Net	641	4,500	6,496
Cash Provided by (Used for) Current Assets and Current Liabilities:			
Change in Receivables	8,335	2,430	(7,952)
Change in Inventories	(3,345)	(687)	(5,286)
Change in Other Current Assets	(4,216)	7,019	(1,072)
Change in Payables and Other Current Liabilities	11,321	30,056	(4,775)
Change in Interest Payable and Income Taxes Receivable/Payable	(513)	(14,141)	(7,236)
Net Cash Provided by Continuing Operations	150,283	168,986	93,678
Net Cash (Used in) Provided by Discontinued Operations	(2,502)	64,561	10,705
Net Cash Provided by Operating Activities	147,781	233,547	104,383
Cash Flows from Investing Activities			
Capital Expenditures	(164,463)	(115,762)	(67,360)
Proceeds from Disposal of Noncurrent Assets	3,764	4,889	1,923
Net Increase in Other Investments	(1,845)	(1,037)	(40)
Net Cash Used in Investing Activities - Continuing Operations	(162,544)	(111,910)	(65,477)
Net Proceeds from Sale of Discontinued Operations	12,842	42,229	107,310
Net Cash Provided by (Used in) Investing Activities - Discontinued Operations	505	(13,896)	(36,410)
Net Cash (Used in) Provided by Investing Activities	(149,197)	(83,577)	5,423
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	--	--	(7,268)
Net Short-Term Borrowings (Repayments)	51,195	--	(79,490)
Proceeds from Issuance of Common Stock	1,821	--	--
Common Stock Issuance Expenses	(3)	(370)	--
Payments for Retirement of Capital Stock	(15,723)	(111)	(1,182)
Proceeds from Issuance of Long-Term Debt	40,900	--	142,006
Short-Term and Long-Term Debt Issuance Expenses	(522)	(897)	(1,666)

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Payments for Retirement of Long-Term Debt	(72,981)	(50,224)	(100,796)
Premium Paid for Early Retirement of Long-Term Debt	(9,889)	(12,500)	--
Dividends Paid and Other Distributions	(43,818)	(43,976)	(43,923)
Net Cash Used in Financing Activities - Continuing Operations	(49,020)	(108,078)	(92,319)
Net Cash Used in Financing Activities - Discontinued Operations	--	(4,278)	(3,184)
Net Cash Used in Financing Activities	(49,020)	(112,356)	(95,503)
Net Change in Cash and Cash Equivalents - Discontinued Operations	(776)	(1,246)	2,015
Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations	--	--	(324)
Net Change in Cash and Cash Equivalents	(51,212)	36,368	15,994
Cash and Cash Equivalents at Beginning of Period	52,362	15,994	--
Cash and Cash Equivalents at End of Period	\$1,150	\$52,362	\$15,994
See accompanying notes to consolidated financial statements.			

OTTER TAIL CORPORATION

Consolidated Statements of Capitalization, December 31

(in thousands, except share data)

	2013	2012
Short-Term Debt		
Otter Tail Power Company Credit Agreement	\$ 51,195	\$ --
Total Short-Term Debt	\$ 51,195	\$ --
Long-Term Debt		
Obligations of Otter Tail Corporation		
9.000% Notes, due December 15, 2016	\$ 52,330	\$ 100,000
North Dakota Development Note, 3.95%, due April 1, 2018	325	393
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	1,223	1,332
Total – Otter Tail Corporation	53,878	101,725
Obligations of Otter Tail Power Company		
Unsecured Term Loan - LIBOR plus 0.875%, due January 15, 2015	40,900	--
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000	33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017, retired early on March 1, 2013	--	5,065
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
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022, retired early on March 1, 2013	--	20,070
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000	42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000	50,000
Total – Otter Tail Power Company	335,900	320,135
Total	389,778	421,860
Less:		
Current Maturities – Otter Tail Corporation	188	176
Unamortized Debt Discount – Otter Tail Corporation	1	4
Total Long-Term Debt	389,589	421,680
Cumulative Preferred Shares—Without Par Value (Stated and Liquidating Value \$100 a Share)— Authorized 1,500,000 Shares; nonvoting and redeemable at the option of the Company:		
Series Outstanding December 31, 2012:		
\$3.60, 60,000 Shares; redeemed on March 1, 2013	--	6,000
\$4.40, 25,000 Shares; redeemed on March 1, 2013		