Otter Tail Corp
Form 10-K
February 29, 2012

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
(X) Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2011

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

Commission File Number 0-53713

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

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

215 SOUTH CASCADE STREET, BOX 496, FERGUS FALLS, MINNESOTA	56538-0496
(Address of principal executive offices)	(Zip Code)

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

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

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

Securities registered pursuant to Section 12(g) of the Act:
CUMULATIVE PREFERRED SHARES, without par value

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)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). (Yes _X_ 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. (X)

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 (X)	Accelerated Filer ( )
Non-Accelerated Filer ( ) (Do not check if a smaller reporting company)	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 X)

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 30, 2011 was $750,816,323.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 36,104,395 Common Shares ($5 par value) as of February 15, 2012.

Documents Incorporated by Reference:

Proxy Statement for the 2012 Annual Meeting-Portions incorporated by reference into Part III

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PART I

Item 1. BUSINESS

(a) General Development of Business

Otter Tail Power Company was incorporated in 1907 under the laws of the State of Minnesota. In 2001, the name was changed to "Otter Tail Corporation" to more accurately represent the broader scope of 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. Its 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, Canada and Mexico. The Company had approximately 3,155 full-time employees in its continuing operations at December 31, 2011.

In 2011, in execution of the Company's announced strategy of realigning its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations, the Company sold Idaho Pacific Holdings, Inc. (IPH), its Food Ingredient Processing business, and E.W. Wylie Corporation (Wylie), its trucking company headquartered in West Fargo, North Dakota, which was included in its Wind Energy segment. On January 18, 2012, the Company sold the assets of Aviva Sports, Inc. (Aviva), a wholly owned subsidiary of the Company's waterfront equipment manufacturer that sells a variety of recreational equipment. On February 6, 2012, the Company entered into an agreement to sell DMS Health Technologies, Inc. (DMS), its Health Services business. The closing, which is subject to certain closing conditions, is expected to occur by February 29, 2012. As a result of these transactions, the Company's business structure no longer includes Health Services or Food Ingredient Processing segments, and now includes the remaining five segments: Electric, Wind Energy, Manufacturing, Construction and Plastics. The chart below indicates the companies now included in each segment.

All information in this report, including comparative financial information, has been revised to reflect the continuing operations of the Company's business 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 Midwest Independent Transmission System Operator (MISO) markets. OTP's operations have been the Company's primary business since 1907. Additionally, Electric also includes Otter Tail Energy Services Company (OTESCO), which provides technical and engineering services.

Wind Energy consists of a steel fabrication company primarily involved in the production of wind towers sold in the United States and Canada, with manufacturing facilities in North Dakota, Oklahoma and an idled plant in Fort Erie, Ontario, Canada.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping and fabrication, and production of waterfront equipment, material and handling trays and horticultural containers. These businesses have manufacturing facilities in Florida, Illinois, and Minnesota and sell products primarily in the United States.

Construction consists of businesses involved in residential, 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.

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe in the upper Midwest and Southwest regions of the United States.

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.

OTP and OTESCO are wholly owned subsidiaries of the Company. All of the Company’s other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar).

The Company’s current strategy is to 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. By adding to the utility earnings base and reducing the size of its nonelectric holdings, the Company also plans to lower its overall risk, create a more predictable earnings stream, improve its credit quality and preserve its ability to fund the dividend. Over time, the Company expects the electric utility business will provide approximately 75% to 85% of its overall earnings. The Company expects its nonelectric businesses will provide 15% to 25% of its earnings, and will continue to be a fundamental part of its strategy.

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 41 through 63 of this Annual Report on Form 10-K.

(b) Financial Information about Industry Segments

The Company is engaged in continuing businesses that have been classified into five segments: Electric, Wind Energy, Manufacturing, Construction and Plastics. Financial information about the Company's continuing segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 81 through 83 of this Annual Report on Form 10-K.

(c) Narrative Description of Business

ELECTRIC

General

Electric consists of two businesses: OTP and OTESCO. OTP, headquartered in Fergus Falls, Minnesota, provides electricity to more than 129,000 customers in a 50,000 square mile area of Minnesota, North Dakota and South Dakota. OTESCO, headquartered in Fergus Falls, Minnesota, provides technical and engineering services primarily in North Dakota and Minnesota. The Company derived 32%, 39% and 38% of its consolidated operating revenues from the Electric segment for each of the three years ended December 31, 2011, 2010 and 2009, respectively.

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

State	2011	2010
Minnesota	48.8 %	48.9 %
North Dakota	42.2	41.2
South Dakota	9.0	9.9
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 423 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, 2011, OTP served 129,259 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	2011	2010
Commercial	36.2 %	36.4 %
Residential	32.9	31.3
Industrial	23.8	23.3
All Other Sources	7.1	9.0
Total	100.0 %	100.0 %

Wholesale electric energy kilowatt-hour (kwh) sales were 12.9% of total kwh sales for 2011 and 18.4% for 2010. Wholesale electric energy kwh sales decreased by 34.1% between the years while revenue per kwh sold decreased by 34.2%. 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

As of December 31, 2011 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants	
Big Stone Plant	257,800 kW

Coyote Station	146,400
Hoot Lake Plant	140,900
Total Baseload Net Plant	545,100 kW
Combustion Turbine and Small Diesel Units	108,000 kW
Hydroelectric Facilities	2,700 kW
Owned Wind Facilities (rated at nameplate)	
Luverne Wind Farm (33 turbines)	49,500 kW
Ashtabula Wind Center (32 turbines)	48,000
Langdon Wind Center (27 turbines)	40,500
Total Owned Wind Facilities	138,000 kW

The baseload net plant capacity for Big Stone Plant and Coyote Station constitutes OTP’s ownership percentages of 53.9% and 35%, respectively. OTP owns 100% of the Hoot Lake Plant. During 2011, OTP generated about 75.3% 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, 2011:

Purchased Wind Power Agreements (rated at nameplate and greater than 2,000 kW)		
Edgeley		21,000 kW
Langdon	19,500	
Total Purchased Wind		40,500 kW
Other Purchased Power Agreements (in excess of 1 year and 500 kW)		
Wisconsin Electric Power Company		50,000 kW
Great River Energy1	50,000	
Western Area Power Administration	5,500	
Total Purchased Power		105,500 kW

1Increases to 100,000 kW from January 2015 through May 2017.

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 Planning Resource Credits to meet its monthly weather normalized forecast demand, plus a reserve obligation. OTP met its MISO obligation for all months in 2011. MISO is currently in discussions with the Federal Energy Regulatory Commission (FERC) and stakeholders to initiate changes to its Resource Adequacy Construct. Any changes would be effective beginning June 1, 2012. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2012 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 and Big Stone plants burn western subbituminous coal.

The following table shows the sources of energy used to generate OTP’s net output of electricity for 2011 and 2010:

Sources	2011 Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated	2010 Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated
Subbituminous Coal	2,125,170	56.7 %	2,499,132	61.2 %
Lignite Coal	1,062,153	28.3	1,060,954	26.0
Wind and Hydro	527,913	14.1	478,230	11.7
Natural Gas and Oil	33,367	0.9	45,116	1.1
Total	3,748,603	100.0 %	4,083,432	100.0 %

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, 2012
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	May 4, 2016
Hoot Lake Plant	Cloud Peak Energy Resources LLC	Wyoming subbituminous	December 31, 2012

The contract with Dakota Westmoreland Corporation expires on May 4, 2016. The Coyote owners are evaluating future fuel supply alternatives for Coyote Station, including both lignite and western subbituminous fuel.

OTP has about 75% of its coal needs for Big Stone Plant and Hoot Lake Plant under contract for 2012. The remaining 2012 requirements will be secured later in 2012. OTP has no coal contracts in place for 2013 and beyond. OTP is currently monitoring market prices for subbituminous coal and expects to issue requests for proposals for a portion of its expected 2013 and 2014 requirements in the spring of 2012. 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 the 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 the 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 each of the three years 2011, 2010 and 2009 was $1.922, $1.813 and $1.726, 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:

		2011		2010	
Rates	Regulation	% of Electric Revenues	% of kwh Sales	% of Electric Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	45.1 %	42.2 %	43.2 %	39.9 %
ND Retail Sales	ND Public Service Commission	39.1	36.5	36.5	33.4
SD Retail Sales	SD Public Utilities Commission	8.3	8.4	8.8	8.3
Transmission & Wholesale	Federal Energy Regulatory Commission	7.5	12.9	11.5	18.4
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 cover 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 has also 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 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 nonelectric 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.

The Minnesota Division of Energy Resources, part of the Minnesota Department of Commerce (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 Filing—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 (see discussion below), (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 (FCA). 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 rates of return will be 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. On July 1, 2010, OTP filed its plan for 2011-2013. 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 Minnesota's Conservation Improvement Programs through the use of an annual recovery mechanism approved by the MPUC.

OTP has a regulatory asset of $7.4 million for allowable costs and financial incentives that are eligible for recovery through the MNCIP rider that have not been billed to Minnesota customers as of December 31, 2011. A final order regarding the 2010 MNCIP financial incentive was issued by the MPUC on December 22, 2011, approving the recovery of $3.5 million in financial incentives. Beginning in January 2012, OTP's MNCIP surcharge increased from 3.0% to 3.8% for all Minnesota retail electric customers. OTP has recognized $2.2 million in financial incentives related to 2011.

Integrated Resource Plan (IRP)—Minnesota law requires utilities to submit to the MPUC for approval a 15-year advance IRP. The MPUC's findings of fact and conclusions regarding resource plans shall be considered prima facie evidence, subject to rebuttal, in Certificate of Need (CON) hearings, rate reviews and other proceedings. Typically, the filings are submitted every two years.

On June 25, 2010 OTP filed its 2011-2025 IRP with the MPUC. The MNDOC requested and was granted an extension of the initial comment period to March 1, 2011. Presentations of the 2011-2025 IRP were made to both the NDPSC and SDPUC. Approximately 60% of the 2011-2025 IRP is comprised of improvements at existing resources and wholesale energy purchases similar to existing levels. The remaining 40% of the plan is comprised of the following components: 64% natural gas simple cycle combustion turbines, 21% conservation and demand response, and 15% wind generation. Capacity additions proposed in the 2011-2025 IRP are as follows:

Resource	Proposed
Natural gas	213 MW
Demand Response/Conservation	70 MW
Wind	50 MW

On December 20, 2011 and February 9, 2012, respectively, the MPUC approved and issued a written order approving OTP's 2011-2025 IRP, subject to the following conditions, among others:

Preparation and submission of a base-load diversification study specifically focused on evaluating retirement and repower options for Hoot Lake Plant to be filed no later than November 8, 2012. This study should evaluate the costs and OTP's plans related to the Environmental Protection Agency's (EPA) rules and how they might impact OTP operations. It also should include implications to transmission system reliability of any changes to Hoot Lake Plant.

Future OTP IRPs should include carbon dioxide (CO2) costs at the mid-point of the commission-approved range in the base case and also should include market costs for sulfur dioxide (SO2) allowances. Future OTP IRPs should use the most current MISO long-term wind capacity credit or an average of its historical wind capacity credits.

OTP should increase its wind additions to 100 megawatts (MW) from the 50 MW of additional wind included in its five-year preferred plan, assuming the prices are reasonable.

For resource planning purposes, the MPUC approved OTP's 1.2% energy savings target and encouraged OTP to expand its demand-response and energy-efficiency portfolio. OTP's next IRP filing is due no later than December 1, 2013.

Renewable Energy Standards, Conservation, Renewable Resource Riders—The Minnesota legislature has enacted a statute that favors conservation over the addition of new resources. In addition, it 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. 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: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. 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 has sufficient renewable energy resources available and in service to comply with the required 2012 level of 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.

On January 12, 2010 the MPUC issued an order finding OTP's Luverne Wind Farm project eligible for cost recovery through the Minnesota Renewable Resource Adjustment (MNRRA). The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010. The MPUC approved OTP's petition for a 2010 MNRRA in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the MNRRA to $0.00684 per kwh plus $0.298 per kW for the large general service class, and $0.00760 per kwh for all other customer classes. The 2010 MNRRA was established with an expected recovery of $16.2 million over the period September 1, 2010 to August 31, 2011.

OTP has a regulatory asset of $2.8 million for revenues that are eligible for recovery through the MNRRA rider that have not been billed to Minnesota customers as of December 31, 2011. The recovery of MNRRA costs was 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 this regulatory asset, which will be recovered under the MNRRA rider over a period ending in September 2014.

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 otherwise deemed eligible by the MPUC. 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 request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010 OTP's TCR rider rate is reflected on Minnesota customer electric service statements at $0.00039 per kwh plus $0.035 per kW for large general service customers and $0.00007 per kwh for controlled service customers, $0.00025 per kwh for lighting customers, and $0.00057 per kwh for all other customers.

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 currently being recovered through OTP's Minnesota TCR rider to recovery in base rates. Final rates went into effect on October 1, 2011. The Company will continue to utilize the rider cost recovery mechanism until the remaining balance of the current transmission projects has been collected as well as to recover costs associated with approved regional projects. OTP filed a request for an update to its Minnesota TCR rider on October 5, 2010. Comments and reply comments have been filed but the MPUC has not yet scheduled a hearing on the request.

Power Plant Siting and Transmission Line Routing—Pursuant to the Minnesota Power Plant Siting Act, the MPUC has been granted the authority to regulate the siting in Minnesota of large electric generating facilities in an orderly manner compatible with environmental preservation and the efficient use of resources. To that end, the MPUC is empowered, after an environmental impact study is conducted by the MNDOC and the Office of Administrative Hearings conducts contested case hearings, 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) and to certify such sites and routes as to environmental compatibility.

The Minnesota legislature enacted the Minnesota Energy Security and Reliability Act in 2001. Its primary focus was to streamline the siting and routing processes for the construction of new electric generation and transmission projects. The bill also added to utility requirements for renewable energy and energy conservation. The legislation later transferred environmental review authority from the Environmental Quality Board to the MNDOC.

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, by a vote of 5-0, a motion to grant the CON and Route Permit for the Minnesota portion of the Big Stone II transmission line.

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 CO_2 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 continues to be evaluated.

On December 14, 2009 OTP filed a request with the MPUC for deferred regulatory accounting treatment for the costs incurred related to the cancelled Big Stone II plant. 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 was $3.2 million (which excludes $3.2 million of project transmission-related costs). As of December 31, 2011, OTP had a regulatory asset of $2.6 million of Big Stone II generation costs to be recovered.

On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone transmission facilities. The request asked to extend the deadline for filing a CON for these transmission facilities until March 17, 2013. The April 25, 2011 MPUC order instructed OTP to transfer the $3.2 million Minnesota share of Big Stone II transmission costs to Construction Work in Progress (CWIP) and to create a tracker account through which any over or under recoveries could be accumulated for refund or recovery determination in future rate cases as a regulatory liability or asset. If determined eligible for recovery under the FERC-approved MISO regional transmission tariff, the Minnesota portion of Big Stone II transmission costs and accumulated Allowance for Funds Used During Construction (AFUDC) will receive rate base treatment and recovery through the FERC-approved MISO regional transmission rates. Any amounts over or under collected through MISO rates will be reflected in the tracker account.

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 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.

On April 16, 2009 the MPUC approved CONs for the three 345 kV Group 1 CapX2020 line projects: the Fargo Project, the Brookings Project and the Twin Cities–LaCrosse 345 kV Project.

The Fargo Project—The route permit application for the Monticello to St. Cloud portion of the Fargo Project was filed in April 2009. The MPUC approved the route permit application and issued a written order on July 12, 2010. Required permits from the Minnesota Department of Transportation, Minnesota Department of Natural Resources and the U.S. Army Corps of Engineers were received in 2010. A Transmission Capacity Exchange Agreement, allocating transmission capacity rights to owners across the Monticello to St. Cloud portion of the Fargo Project, was accepted by the FERC in the third quarter of 2010. The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. OTP's share of this project is approximately $13.1 million.

The Minnesota route permit application for the St. Cloud to Fargo portion of the Fargo Project was filed on October 1, 2009. Minnesota State Environmental Impact Statement (EIS) scoping meetings were held in September 2010 and public hearings were held in November 2010. The MPUC approved the route permit on June 24, 2011. The agreements for Phase 2, which consists of the line section between St. Cloud and Alexandria, Minnesota, were signed by all of the participants on August 3, 2011. Easement acquisition discussions with landowners are underway. Construction began in November 2011. Phase 2 of the Fargo project is expected to be placed in service in the fourth quarter of 2013 and OTP’s share of the costs is expected to be $31.5 million.

The Brookings Project—The Minnesota route permit application for the Brookings Project was filed in the fourth quarter of 2008. The MPUC approved the final line segment route permit for the Brookings Project on February 3, 2011. OTP executed project agreements with its partners on January 13, 2012. This project will be placed into service in segments with the earliest segment being placed in-service in the summer of 2013 and the last segment placed in-service during the first quarter of 2015. OTP's share of the costs is expected to be $28.1 million.

The Bemidji Project—OTP serves as the lead utility for the Bemidji Project, which has an expected in-service date in late 2012. The MPUC approved the CON for this project on July 9, 2009. A route permit application was filed with the MPUC in the second quarter of 2008 and approved on October 28, 2010. The joint state and federal EIS was published by federal agencies on September 7, 2010, and the project's Transmission Capacity Exchange Agreement was accepted and approved by the FERC in the third quarter of 2010. On March 25, 2011, the Leech Lake Band of Ojibwe (LLBO) submitted a petition to the MPUC, requesting the revocation or suspension of the project's route permit. The request is based on the LLBO's allegation that it has jurisdiction to require the project to obtain its permission to cross through the historical boundaries of the Leech Lake Reservation. The owners of the Bemidji Project, including OTP, filed reply comments in opposition to the LLBO's request. On April 25, 2011, the Bemidji Project owners filed a declaratory judgment in the U.S. District Court for Minnesota against the LLBO seeking a judgment that no consent from the LLBO is required for the project to run through the LLBO reservation boundaries since the project is located exclusively on non LLBO lands. On June 22, 2011, Federal District Judge Frank issued a preliminary injunction which ordered the LLBO to cease and desist from pursuing its claims of jurisdiction over the project in tribal court or the MPUC and from taking any other actions to interfere with the routing or construction of the project. The parties had engaged in court supervised mediation; however, no agreement was reached. The preliminary injunction remains in place prohibiting the LLBO from interfering with project construction, which began in December 2010. The in-service date for this project is expected to be in the fourth quarter of 2012 and OTP's share of the costs is expected to be $24.3 million.

Recovery of OTP's CapX2020 transmission investments will be through the MISO tariff and the Minnesota, North Dakota and South Dakota TCR Riders.

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. OTP's current capital structure petition is in effect until the MPUC issues a new capital structure order for 2012. OTP is required to file its 2012 capital structure petition by May 1, 2012.

Big Stone Air Quality Control System (AQCS) Request for Advance Determination of Prudence (ADP)—Minnesota law authorizes a public utility to petition the MPUC for an 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. ADPs can help lower the cost of financing by providing additional regulatory certainty, which ultimately reduces customer costs. On January 14, 2011 OTP filed a petition asking the MPUC for an ADP for 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. On December 20, 2011 the MPUC decided that OTP met the requirements of the ADP statute and granted OTP's petition for advanced determination of prudence for the Big Stone Plant AQCS.

North Dakota

OTP is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities 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 new electric power generating plants exceeding 60,000 kW and proposed new 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 Rate Case—On November 3, 2008 OTP filed a general rate case in North Dakota requesting an overall revenue increase of approximately $6.1 million, or 5.1%, and an interim rate increase of approximately 4.1%, or $4.8 million annualized, that went into effect on January 2, 2009. In an order issued by the NDPSC on November 25, 2009, OTP was granted an increase in North Dakota retail electric rates of $3.6 million, or approximately 3.0%, which went into effect in December 2009. The NDPSC order authorizing an interim rate increase required OTP to refund North Dakota customers the difference between final and interim rates, with interest. OTP established a refund reserve for revenues collected under interim rates that exceeded the final rate increase. The refund reserve balance of $0.9 million as of December 31, 2009 was refunded to North Dakota customers in January 2010. OTP deferred recognition of $0.5 million in rate case-related filing and administrative costs that are subject to amortization and recovery over a three year period beginning in January 2010. As required by the NDPSC order in the OTP 2008 rate case, OTP submitted a filing for a request to remove the recovery of the costs associated with economic development in base rates in North Dakota. OTP proposed and the NDPSC approved an Economic Development Cost Removal Rider, under which all North Dakota customers will receive a credit of $0.00025 per kwh. The monthly credit was effective with bills rendered on and after January 1, 2011.

Renewable Resource Cost Recovery Rider—On May 21, 2008 the NDPSC approved OTP’s request for a Renewable Resource Cost Recovery Rider to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) of $0.00193 per kwh was included on North Dakota customers’ electric service statements beginning in June 2008, and reflects cost recovery for OTP’s twenty-seven 1.5 MW wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008. The rider also allows OTP to recover costs associated with other new renewable energy projects as they are completed. OTP included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008 in its 2009 annual request to the NDPSC to increase the amount of the NDRRA. An NDRRA of $0.0051 per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009. Terms of the approved settlement provide for the recovery of accrued but unbilled NDRRA revenues over a period of 48 months beginning in January 2010.

In a proceeding that was combined with OTP’s general rate case, the NDPSC reviewed whether to move the costs of the projects being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to $0.00369 for the period from December 1, 2009 until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA (which includes cost recovery for OTP’s investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010.

Approval for implementation of an updated NDRRA was received in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the NDRRA to $0.00473 per kwh plus $0.212 per kW for the large general service class, and $0.00551 per kwh for all other customer classes. The 2010 NDRRA was established with an expected recovery of $15.8 million over the period September 1, 2010 to March 31, 2012, which will be in effect until the NDPSC sets another updated NDRRA. On December 29, 2011, OTP submitted its annual update to the renewable rider with a proposed April 1, 2012 effective date. This request changes the NDRRA to $0.00410 per kwh plus $0.705 per kW for the large general service class and increases the rate to $0.00556 per kwh for all other customer classes. The 2011 NDRRA has an expected recovery of $10.1 million over the period April 1, 2012 to March 31, 2013.

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. OTP requested recovery of such costs in its general rate case filed in

November 2008 and was granted recovery of such costs by the NDPSC in its November 25, 2009 order. OTP filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011. An evidentiary hearing was held on January 24, 2012, and the NDPSC's determination on OTP's request is pending. On February 10, 2012, OTP filed initial briefs and proposed findings. A NDPSC work session is scheduled for February 16, 2012.

MISO-Related Costs—In February 2005, OTP filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the FCA in North Dakota. The NDPSC granted interim recovery through the FCA in April 2005, but conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between OTP and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, OTP refunded $493,000 of MISO schedule 16 and 17 costs collected through the FCA from April 2005 through July 2007 to North Dakota customers beginning in October 2007 and ending in January 2008. OTP deferred recognition of these costs plus $330,000 in MISO schedule 16 and 17 costs incurred from August 2007 through December 2008 and requested recovery of these deferred costs in its general rate case filed in North Dakota in November 2008. OTP began amortizing its deferred MISO schedule 16 and 17 costs in North Dakota over a 36-month period beginning in December 2009 in conjunction with the implementation of rates approved by the NDPSC in its November 25, 2009 order. As of December 31, 2011 the balance of OTP’s deferred MISO schedule 16 and 17 costs was $343,000. Base rate recovery for on-going MISO schedule 16 and 17 costs was also approved by the NDPSC in its November 25, 2009 order.

Big Stone Plant AQCS Request for ADP—OTP filed an application for an ADP with the NDPSC on May 20, 2011. The NDPSC hired a consulting firm to evaluate the ADP request. Evidentiary hearings were held on November 29, 2011, and there was no opposition in this proceeding. OTP and the NDPSC advocacy staff entered into a settlement agreement that was filed with the NDPSC on January 9, 2012. An NDPSC decision is expected by the end of the first quarter 2012.

Big Stone II Project—A filing in North Dakota for an ADP of Big Stone II was made by OTP in November 2006. 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. North Dakota’s ADP statute allows a utility to recover costs, and a reasonable return on the costs pending recovery, for a project previously deemed prudent and for which the NDPSC later makes a determination that continuing with the project was no longer prudent.

On December 14, 2009 OTP filed a request with the NDPSC for deferred regulatory accounting treatment for its costs incurred related to cancelled Big Stone II project. 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, which had intervened. 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 excludes $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 August 1, 2010.

The portion of Big Stone II costs incurred by OTP related to transmission is $2.6 million, of which $1.1 million represents North Dakota’s jurisdictional share. OTP transferred the North Dakota Share of Big Stone II transmission costs to CWIP, with such costs subject to AFUDC continuing from September 2009. If construction of all or a portion of the transmission facilities commences within three years of the NDPSC order approving the settlement agreement, the North Dakota portion of Big Stone II transmission costs and accumulated AFUDC shall be included in the rate base investment for these future transmission facilities. If construction is not commenced on any of the transmission facilities within three years of the NDPSC order approving the settlement agreement, OTP may petition the NDPSC to either continue accounting for these costs as CWIP or to commence recovery of such costs.

CapX2020 - Fargo Project— On October 8, 2010, OTP submitted its application for a Certificate of Public Convenience and Necessity (CPCN) from the NDPSC for the North Dakota portion of the Fargo Project. The NDPSC approved the CPCN in January 2011. The application for the North Dakota Certificate of Corridor Compatibility (CCC) was filed on December 30, 2010 and was revised in March 2011. The June 23, 2011 hearing for the North Dakota CCC application was postponed. A combined North Dakota CCC and route permit application was submitted to the NDPSC on October 3, 2011. The NDPSC conducted a hearing on January 30, 2012, and the project expects to receive final permit approval from the NDPSC by the second quarter of 2012. Once all final permits have been received from the NDPSC, project agreements for Phase 3, which consists of the line section between Alexandria, Minnesota, and Fargo, North Dakota, would be executed with the project partners. The in-service date for Phase 3 is estimated to be the first quarter of 2015. OTP's total expected capital investment in this phase of the Fargo Project is $49.0 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 hearing occurred on July 25, 2011. On August 23, 2011, an executed settlement agreement on continued prudence was filed and the hearing for consideration of the settlement agreement on continued prudence was held on October 26, 2011. A final decision was issued by the NDPSC on November 10, 2011 granting an ADP, conditioned on the MISO MVP cost allocation remaining unchanged.

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, 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.

2008 General Rate Case Filing—On October 31, 2008 OTP filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which included, among other things, recovery of investments and expenses related to renewable resources. OTP increased rates by approximately 11.7% on a temporary basis beginning with electricity consumed on and after May 1, 2009, as allowed under South Dakota law. In an order issued by the SDPUC on June 30, 2009, OTP was granted an increase in South Dakota retail electric rates of $3.0 million or approximately 11.7%. OTP implemented final, approved rates in July 2009.

2010 General Rate Case Filing—On August 20, 2010 OTP filed a general rate case with the SDPUC requesting an overall revenue increase of approximately $2.8 million, or just under 10.0%, which includes, among other things, recovery of investments and expenses related to renewable resources. On September 28, 2010 the SDPUC suspended OTP's proposed rates for a period of 180 days to allow time to review OTP's proposal. On January 19, 2011 OTP submitted a proposal to use current rate design to implement an interim rate in South Dakota to be effective on and after February 17, 2011. On January 26, 2011 OTP submitted an amended proposal to use a lower interim rate increase than originally proposed. At its February 1, 2011 meeting, the SDPUC approved OTP's request to implement interim rates using current rate design and the lower interim increase to be effective on and after February 17, 2011. On April 21, 2011, the SDPUC issued its written order approving an overall final revenue increase of approximately $643,000 (2.32%) and an overall rate of return on rate base of 8.50% for the interim rates and final rates. 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. OTP's TCR rider rate is reflected on South Dakota customer electric service statements at $0.00083 per kwh plus $0.072 per kW for large general service customers, $0.00020 per kwh for controlled service customers, $0.00108 per kwh for lighting customers, and $0.00180 per kwh for all other customers. The projected revenue for the period of December 1, 2011 through December 31, 2012 is approximately $616,000.

Big Stone II Project—On December 14, 2009 OTP filed a request with the SDPUC for deferred regulatory accounting treatment for its costs incurred related to the cancelled Big Stone II plant. The SDPUC approved OTP's request for deferred accounting treatment on February 11, 2010. 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 will be 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.

CapX2020 Brookings–Southeast Twin Cities 345 kV Project—An application for a South Dakota facility route permit was filed with the SDPUC on November 22, 2010. The SDPUC conducted a public hearing in January 2011 and the South Dakota route permit was approved in June 2011.

Energy Efficiency Plan—On January 4, 2007 the SDPUC encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use. On July 28, 2008 the SDPUC approved OTP's energy efficiency plan for South Dakota customers. 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 its 2010 South Dakota Energy Efficiency Plan 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 program into 2011.

On April 29, 2011 OTP filed a request with the SDPUC for approval of a 2010 financial incentive of $73,415 and a surcharge adjustment of $0.00063 on South Dakota customer's bills. On May 25, 2011 OTP filed a request with the SDPUC for approval of updates to its 2012-2013 South Dakota Energy Efficiency Plan. The SDPUC approved the 2012-2013 plan with a maximum available incentive payment limited to 30% of the budget amount provided in the plan.

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, which has 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 Open Access Transmission, Energy and Operating Reserve Markets Tariff (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) specifically for three regional transmission CapX2020 projects that OTP is investing in: 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 Multi-Value Projects (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. The MVP cost allocation is currently being challenged in the Seventh Circuit of the United States Court of Appeals.

On November 3, 2011 OTP filed with the FERC to request transmission incentive rate treatment for two MVPs. The two MVPs, which were granted approval by MISO on December 8, 2011, are the Big Stone South–Brookings Project and the Ellendale–Big Stone South Project. On December 30, 2011, the FERC approved OTP's request. The approved incentive rate treatment will provide for the inclusion in rate base of in-process construction costs during development and construction of the projects and, in the event that either of the projects is abandoned for reasons outside of OTP's control, will allow OTP to petition the FERC for recovery of any abandonment plant costs on the basis that the costs were prudently incurred. Effective on January 1, 2012 the FERC authorized OTP to recover 100% CWIP and Abandoned Plant Recovery on the Big Stone South–Brookings Project and the Ellendale–Big Stone South Project. OTP's total expected capital investment in these two projects in the years 2012 through 2016 is approximately $117.7 million.

CapX2020 Brookings–Southeast Twin Cities 345 kV Project—In June of 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.

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 46 states and Canada. NAEMA was formed in May 2003 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 (NERC). The MRO is responsible for: (1) developing and implementing reliability standards, (2) enforcing compliance with those standards, (3) providing seasonal and long-term assessments of the bulk power system’s ability to meet demand for electricity, and (4) providing an appeals and dispute resolution process.

The MRO region covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska and the majority of 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 12 states and the Canadian province of Manitoba. The MISO began operational control of OTP’s transmission facilities above 100 kV on February 1, 2002 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 market 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.

In December 2008 pursuant to the provisions of the MISO Transmission Owners Agreement, OTP sent MISO a letter of intent to withdraw from MISO on or after December 31, 2009. This procedural step was taken to allow OTP the earliest available opportunity to withdraw from MISO if its concerns about the unintended consequences produced by the MISO Tariff, which imposed a disproportionate allocation of charges to its customers, attributable to the allocation of costs for transmission network upgrades, cannot be equitably resolved. Withdrawal from MISO would require OTP to either secure replacement of and/or self-provide the services currently provided by MISO. OTP’s notice remains in effect.

Other

OTP is subject to various federal and state laws, including the Federal 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 Comprehensive 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, 2011 OTP invested approximately $21.2 million in environmental control facilities. The 2012 construction budget includes approximately $32.0 million 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 turbine generator, which is the smallest of the three coal-fired units at Hoot Lake Plant, was retired as of December 31, 2005. OTP had initially retained the unit 1 boiler for use as a source of emergency heat, but provisions have been made to use a portable fuel-oil boiler to replace the unit 1 boiler for emergency heat. 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 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 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 (NOx).

The national SO2 emission reduction goals are achieved through a market based system under which power plants are allocated "emissions allowances" that will 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 NOx emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. All of OTP's generating facilities met the NOx standards during 2011.

The EPA Administrator signed the final Interstate Air Quality Rule, also known as the Clean Air Interstate Rule (CAIR), on March 10, 2005. The EPA has concluded that SO2 and NOx are the chief emissions contributing to interstate transport of particulate matter less than 2.5 microns (PM2.5). The EPA also concluded that NOx 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 PM2.5 nonattainment in downwind states. On that basis, the EPA proposed to cap SO2 and NOx 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 NOx reduction for ambient air quality 8-hour ozone nonattainment purposes. On July 11, 2007, 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 and remanded the case for the EPA to conduct further proceedings consistent with the court's prior opinion. 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 conducts 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 is proposed to include Minnesota sources due to a finding that Minnesota's emissions contribute to PM2.5 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), which is a replacement for the Transport Rule, on July 8, 2011. The CSAPR requires states to improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. 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, and 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 order requires EPA to continue administering CAIR while CSAPR is stayed. The order also requires parties to submit formats and schedules for briefing the cases that would allow the cases to be heard by April 2012. Due to the uncertainties surrounding the outcome of the legal challenges, at this time the impact of the rule on OTP is uncertain. Neither North Dakota nor South Dakota sources are regulated by the CSAPR.

Air Quality – Hazardous Air Pollutants—The CAA calls for the EPA to study the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and submitted reports to Congress. The CAA required the EPA to make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced it affirmatively decided to regulate mercury emissions from electric generating units, and final rules were published on June 9, 2006 based on a cap and trade approach. On February 8, 2008 the U.S. Court of Appeals for the D.C. Circuit granted petitions for review of the EPA rules and on March 14, 2008 the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating the EPA final rule regulating utility mercury emissions. The EPA appealed the court's decision to the U.S. Supreme Court, but withdrew its appeal in early 2009. The Supreme Court denied the appeals of other parties to the litigation on February 23, 2009. The EPA rulemaking is proceeding under the maximum achievable control technologies (MACT) provision of the CAA Section 112(d) for existing units and Section 112(g) case-by-case MACT provisions for affected new units. 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). The final rule was published in the Federal Register on February 16, 2012. The power plants have three years and 60 days from the date of publication to comply with MATS. 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 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 initial review of the final rule, it appears that OTP's affected units would meet the requirements by installing the AQCS system at Big Stone, by adding fabric filters on Hoot Lake Units 2 and 3, and by installing mercury control technology such as activated carbon injection on all units. Emissions monitoring equipment and/or stack testing will also be needed to verify compliance with the standards. Mercury emissions monitoring equipment installation is complete at Big Stone Plant and Coyote Station, but operation of the equipment has been delayed pending implementation of the final 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 their 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.

On September 22, 2008, the Sierra Club notified OTP and the two other Big Stone Plant co-owners of its intent to sue alleging violations of the Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) requirements of the CAA with respect to two past plant activities. The Sierra Club stated that unless the matter was otherwise fully resolved, it intended to file suit in the applicable district courts any time 60 days after the September 22, 2008 letter. As of the date of this report the Sierra Club has not filed suit in the applicable district courts as contemplated in the September 22, 2008 notification. OTP believes that the Big Stone Plant is in material compliance with all applicable requirements of the CAA.

Air Quality – Regional Haze Program—On June 15, 2005 the EPA signed the BART rule. The rule requires emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone 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. On November 2, 2009 OTP submitted to DENR its analysis of what control technology should be considered BART for NOX, SO2, and particulate matter for the Big Stone Plant.

On January 15, 2010 the DENR provided OTP with a copy of South Dakota’s draft proposed Regional Haze State Implementation Plan (SIP). Comments were requested on or before March 16, 2010. South Dakota’s draft proposed Regional Haze SIP recommended the SO2 and particulate matter emission control technology and emission rates that generally followed OTP’s BART analysis. The DENR recommended a Selective Catalytic Reduction (SCR) technology for NOx emission reduction in addition to the OTP-recommended separated over-fire air. At that time OTP estimated the cost of the BART technologies based on the DENR proposal to be approximately $223 million for Big Stone Plant ($120 million OTP share). OTP commissioned Sargent & Lundy to conduct a conceptual design study and prepare more detailed estimated costs for the control technology needed to comply with the South Dakota DENR BART determination. That work was completed by the end of October 2010.

South Dakota developed and submitted its implementation plan and associated implementation rules to the EPA on January 21, 2011. The DENR and the EPA have agreed on non-substantive rule revisions, which were adopted by the Board of Minerals and Environment and became effective on September 19, 2011. South Dakota submitted a revised implementation plan and associated implementation rules to the EPA on September 19, 2011. On December 8, 2011, EPA published its proposed approval of the Regional Haze SIP, including the Big Stone BART determination, in the Federal Register. Comments on the proposed approval needed to be received by the EPA on or before February 6, 2012. Per a proposed consent decree, EPA is required to sign a final notice of approval or disapproval of the South Dakota Regional Haze SIP by March 29, 2012. Under the South Dakota implementation plan, and its implementing rules, the Big Stone Plant must install and operate a new BART compliant air quality control system to reduce emissions as expeditiously as practicable, but no later than five years after the EPA’s approval of South Dakota’s implementation plan. Although studies and evaluations are continuing, the current project cost is estimated to be approximately $490 million (OTP’s share would be $265 million).

On January 14, 2011 OTP filed a petition asking the MPUC for an ADP for the design, construction and operation of the BART compliant air quality control system at Big Stone Plant attributable to serving OTP’s Minnesota customers. On December 20, 2011 the MPUC decided that OTP met the requirements of the ADP statute and granted its petition for advanced determination of prudence for the Big Stone Plant AQCS. The MPUC issued its written order granting the ADP on January 23, 2012.

OTP filed an application for an ADP with the NDPSC on May 20, 2011. The NDPSC hired a consulting firm to evaluate the ADP request. Evidentiary hearings were held on November 29, 2011. There was no opposition in this proceeding. OTP and NDPSC advocacy staff entered into a settlement agreement that was filed with the NDPSC on January 9, 2012. An NDPSC decision is expected by the end of the first quarter 2012.

Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The North Dakota Regional Haze SIP requires that Coyote Station reduce its NOx emissions. On February 23, 2010, 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 12-month rolling average basis. The control equipment must be installed by July 1, 2018 and compliance with the limit is required beginning on July 1, 2019. Subsequent to issuance of the construction permit, the NDDOH entered into further negotiations with the EPA on regional haze plan implementation. As part of those negotiations, Coyote Station agreed to accept a NOx emission limit of 0.5 pounds per million Btu as calculated on a 30-day rolling average basis, including periods of start-up and shutdown, beginning on July 1, 2018. The current estimate of the total cost of the project is $6 million ($2.1 million OTP share).

Air Quality – Greenhouse Gas Regulation—The issue of global climate change and the connection between global warming and increased levels of CO_2–a greenhouse gas (GHG)–in the atmosphere is receiving significant attention. Combustion of fossil fuels for the generation of electricity is a major stationary source of CO_2 emissions in the United States and globally. OTP is an owner or part-owner of three baseload, coal-fired electricity generating plants and three fuel-oil or natural gas-fired combustion turbine peaking plants with a combined generating capability of 679 MW. In 2011, these plants emitted approximately 4.0 million tons of CO_2.

OTP monitors and evaluates the possible adoption of national, regional, or state climate change and GHG legislation or regulations that would affect electric utilities. 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 CO_2 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 CO_2 and other GHGs from automobiles as “air pollutants” under the CAA. The Supreme Court sent the case back to 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. The first step in the EPA rulemaking process was the publication of an endangerment finding in the December 15, 2009 Federal Register where the EPA found that CO_2 and five other GHGs – methane, NOx, 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.

On June 6, 2010 the EPA published a final “tailoring rule” that phases in application of its PSD program to GHG emission sources, including power plants. This 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. 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.

The EPA decided to phase in the PSD requirements for GHGs in two steps. Beginning on January 2, 2011, GHG control analysis will be conducted in PSD permit proceedings only if changes at a facility trigger PSD for criteria pollutants and if the proposed change increases GHGs by over 75,000 tons per year of “CO2e,” a measure that converts emissions of each GHG into its carbon dioxide equivalent. Until July 2011 the threshold applies only to facilities currently subject to PSD or Title V permitting. However, as of July 2011, sources emitting more than 100,000 tons per year of CO2e 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, including for GHGs. The DENR reviewed OTP’s projected emissions, including GHG emissions, as a result of the Big Stone 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 AQCS Project on January 6, 2012.

The EPA has announced a timeframe for developing NSPS for GHGs from electric generating units. The EPA planned to propose this NSPS in August 2011, and adopt the standard in June 2012. Recent public sources indicate that the EPA intends to release a proposed rule in early 2012. In general, NSPS become applicable to new sources built after the effective date of the regulation, or affect what may be required to be included as an emission control at the time an existing source makes a change significant enough to trigger NSPS applicability. To trigger the applicability of NSPS, an existing source must make a modification that increases its maximum hourly emissions rate. OTP does not anticipate making modifications at any of its facilities that would trigger NSPS requirements. The Big Stone AQCS project is not projected to trigger the applicability of the NSPS for GHGs that the EPA plans to develop.

At the same time the EPA develops the NSPS, the EPA had also planned to issue emission guidelines for existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike the NSPS, applies to an existing source. States are given a period of time to develop plans to implement a 111(d) Standard, and if a state does not develop such a plan, the EPA will prescribe a plan for that state. A "standard of performance" 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.

Both NSPS and 111(d) Standards involve development of "standards of performance," but the 111(d) Standard 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. 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 GHGs, especially for existing sources, 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.

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 will require retail electricity providers to obtain 25% of the electricity sold to Minnesota customers from renewable sources by the year 2025. 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. Annual updates of the range are required. The MPUC has established the 2009 and 2010 estimates of the likely range of costs of future CO2 regulation on electricity to be between $9/ton and $34/ton.

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: Between 1990 and 2009, OTP decreased its CO2 intensity (lbs. of CO2/megawatt-hour generated) by nearly 23%.

Conservation: Since 1992 OTP has helped its customers conserve more than 1.2 million megawatt-hours of electricity. That is roughly equivalent to the amount of electricity that 110,000 average homes would have used in a year. OTP continues to educate customers about energy efficiency and demand-side management and to work with regulators to develop new programs and measurements. OTP's 2011-2025 IRP calls for an additional 70 MW of conservation impacts by 2025.

Renewable energy: Since 2002, OTP's customers have been able to purchase 100% of their electricity from wind generation through OTP's TailWinds program. 40.5 MW of purchased power agreement wind projects and 138 MW of owned wind resources have been on line since December 2009 for serving OTP's customers.

Other: OTP will continue to participate as a member of the EPA's SF6 (sulfur hexafluoride) Emission Reduction Partnership for Electric Power Systems program. The partnership 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 the central interior of 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 is 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, open 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.

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 draft 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 current draft 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 due to be issued on July 27, 2012. OTP is uncertain of the impact on the potentially affected facilities until the EPA releases the final rule.

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. 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.

While additional requirements may be imposed as part of the EPA's pending rule that could increase the capital and operating costs of OTP's facilities, identification of specific costs would be 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 that 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 their Voluntary Investigation and Cleanup 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.

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 2011, approximately $50 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2011 gross electric property additions, including construction work in progress, were approximately $529 million and gross retirements were approximately $56 million. OTP estimates that during the five-year period 2012-2016 it will invest approximately $730 million for electric construction, which includes $265 million for OTP's share of a new Big Stone Plant AQCS and $226 million for new transmission projects including $118 million for Multi-Value transmission projects in South Dakota and $98 million for CapX2020 transmission projects. The remainder of the 2012-2016 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant.

Franchises

At December 31, 2011 OTP had franchises to operate as an electric utility in all but one incorporated municipality that 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, 2011 OTP had 661 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. One labor contract that expired in the fall of 2011 was renewed under a three-year agreement that expires in the fall of 2014. The other labor contract was renewed in February 2011 and expires in the fall of 2013. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

WIND ENERGY

General

Wind Energy consists of DMI Industries, Inc. (DMI), a steel fabrication company with headquarters in Fargo, North Dakota, that manufactures wind towers and other heavy metal fabricated products. DMI has manufacturing facilities in West Fargo, North Dakota; Tulsa, Oklahoma; and Fort Erie, Ontario, Canada. DMI has a wholly owned subsidiary, DMI Canada, Inc., located in Fort Erie, Ontario, Canada. The Fort Erie plant was idled in the fourth quarter of 2011 due to a lack of orders for wind towers. The Company derived 19%, 16% and 20% of its consolidated operating revenues from the Wind Energy segment for each of the three years ended December 31, 2011, 2010 and 2009, respectively. Two customers account for over 85% of the 2011 revenue of the Wind Energy segment. Following is a brief description of this segment:

Competition

The market in which DMI competes is characterized by competition from both foreign and domestic manufacturers. This market has several established manufacturers with similar specialized equipment capabilities but different market coverage areas than DMI's facilities. The Company believes the principal competitive factors in its Wind Energy segment are strategically located plants, product quality, the delivery capacity to support project schedules and overall cost effectiveness. DMI intends to continue to compete on the basis of high-quality cost-effective products, high levels of capacity to support project deliveries, manufacturing facilities in high demand wind regions and close customer relations and support.

Raw Materials Supply

DMI mainly uses steel in the products it manufactures. Rising prices and availability of steel are concerns for DMI. DMI attempts to mitigate the risk of increases in steel costs by pricing contracts to recover the cost of steel purchased to meet contract requirements at initiation of the contract. Increases in the costs of raw materials that cannot be recovered from customers under contract prices for products could have a negative effect on profit margins in the Wind Energy segment.

Backlog

The Wind Energy segment has backlog in place to support 2012 revenues of approximately $154 million compared with $157 million one year ago.

Legislation

The demand for wind towers manufactured by DMI depends in part on the existence of either renewable portfolio standards or a federal production tax credit for wind energy. Renewable or alternative energy portfolio standards exist in 31 states and eight additional states have renewable or alternative energy portfolio objectives. A federal production tax credit is in place through December 31, 2012.

Capital Expenditures

Capital expenditures in the Wind Energy segment typically include additional investments in new manufacturing equipment or expenditures to replace aged 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 2011, cash expenditures for capital additions in the Wind Energy segment were approximately $6 million. The

Company has $23 million in planned capital expenditures for the Wind Energy segment for the five-year period 2012-2016.

Employees

At December 31, 2011 the Wind Energy segment had 441 full-time employees.

MANUFACTURING

General

Manufacturing consists of businesses engaged in the following activities: contract machining, metal parts stamping and fabrication, and production of waterfront equipment, material and handling trays, and horticultural containers.

The Company derived 21%, 20% and 20% of its consolidated operating revenues from the Manufacturing segment for each of the three years ended December 31, 2011, 2010 and 2009, 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. BTD's location in Washington, Illinois 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.

ShoreMaster, Inc. (ShoreMaster), with headquarters in Fergus Falls, Minnesota, produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems that are marketed throughout the United States. ShoreMaster has two wholly owned operating subsidiaries, Galva Foam Marine Industries, Inc., and Shoreline Industries, Inc. ShoreMaster has manufacturing facilities located in Fergus Falls, Minnesota and St. Augustine, Florida. In January 2012, ShoreMaster discontinued the operations and sold the assets of Aviva, its wholly owned subsidiary that sells a variety of recreational equipment. Aviva is reported under discontinued operations in the consolidated financial statements in this Annual Report on Form 10-K. On January 30, 2012 ShoreMaster closed its Camdenton, Missouri plant and relocated Camdenton's commercial production operations to ShoreMaster's Fergus Falls, Minnesota and St. Augustine, Florida facilities.

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 other industries.

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, ease of use, 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 a variety of raw materials in the products they manufacture, including steel, aluminum, lumber, resin and concrete. 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 the 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 2012 revenues of approximately $121 million compared with $86 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 2011, cash expenditures for capital additions in the Manufacturing segment were approximately $11 million. Total capital expenditures for the Manufacturing segment during the five-year period 2012-2016 are estimated to be approximately $69 million.

Employees

At December 31, 2011 the Manufacturing segment had 1,168 full-time employees. There are 853 full-time employees at BTD, 158 full-time employees at ShoreMaster and 157 full-time employees at T.O. Plastics.

CONSTRUCTION

General

Construction consists of businesses involved in residential, 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%, 15% and 13% of its consolidated operating revenues from the Construction segment for each of the years ended December 31, 2011, 2010 and 2009, respectively. Following is a brief description of the businesses included in this segment:

Foley Company, 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 and a subsidiary company 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 $106 million for 2012 compared with $164 million one year ago.

Capital Expenditures

Capital expenditures in this segment typically include investments in additional construction equipment. During 2011, cash expenditures for capital additions in the Construction segment were approximately $3 million. Capital expenditures during the five-year period 2012-2016 are estimated to be approximately $14 million for the Construction segment.

Employees

At December 31, 2011 there were 701 full-time employees in the Construction segment. Foley Company has 381 employees represented by various unions, including Carpenters and Millwrights, Sheet Metal Workers, Laborers, Operators, Operating Engineers, Pipe Fitters, Steamfitters, Plumbers and Teamsters. Moorhead Electric, Inc., a subsidiary of Aevenia, has 49 employees represented by local unions of the International Brotherhood of Electrical Workers and covered by a labor contract that expires on May 31, 2012. Foley Company has several labor contracts with various expiration dates in 2012 and one contract that expires on May 31, 2013. Moorhead Electric, Inc. and Foley Company have not experienced any strike, work stoppage or strike vote, and consider their present relations with employees to be good.

PLASTICS

General

Plastics consists of businesses producing PVC pipe in the Upper Midwest and Southwest regions of the United States. The Company derived 11%, 11% and 10% of its consolidated operating revenues from the Plastics segment for each of the three years ended December 31, 2011, 2010 and 2009, 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 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, southwestern 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 upper midwest, southwest 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 97% and 98% of total resin purchases in 2011 and 2010, 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 2011, cash expenditures for capital additions in the Plastics segment were approximately $2 million. Total capital expenditures for the five-year period 2012-2016 are estimated to be approximately $10 million to replace existing equipment.

Employees

At December 31, 2011 the Plastics segment had 130 full-time employees. Northern Pipe had 82 full-time employees and Vinyltech had 48 full-time employees as of December 31, 2011.

Item 1A. RISK FACTORS

RISK FACTORS AND CAUTIONARY STATEMENTS

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

GENERAL

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

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

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

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

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

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

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

We were not required to make any contributions to our defined benefit pension plan in 2011. We currently are not required to make any contribution to our defined benefit pension plan in 2012. We made a discretionary contribution to the plan of $10.0 million in January 2012. We could be required to contribute additional capital to the pension plan in future years if the market value of our pension plan assets significantly declines in the future, 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 $39.4 million of goodwill recorded on our consolidated balance sheet as of December 31, 2011. 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.

A sustained decline in our common stock price below book value or declines in projected operating cash flows at any of our operating companies may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

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

Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the actual and projected earnings, cash flows, capital requirements and general financial position of our subsidiary companies, as well as regulatory factors, financial covenants, general business conditions and other matters. Under our $200 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. While this restriction is 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 (losses) earnings in each of the last four 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 diversified 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 realign our mix of diversified businesses through 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 one or more of our nonelectric businesses 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 business sold.

As part of our business strategy, we intend to realign our business portfolio by divesting of some of our nonelectric businesses and building our electric utility’s earnings base in order to lower our overall risk. A loss on the sale of a business would be recognized if a company is sold for less than its book value.

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

Our plans to grow and operate our nonelectric 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.

We enter into production and construction contracts, including contracts for new product designs, 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.

DMI, ShoreMaster and our construction companies frequently provide products and services pursuant to fixed-price contracts. Revenues recognized on jobs in progress under fixed-price contracts were $608 million at December 31, 2011 and $491 million at December 31, 2010. 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 manufacturers, suppliers and subcontractors at the time we enter into fixed-price contracts with our customers.

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 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 to base our warranty estimate on. Our assumptions could be materially different from any actual claim and could exceed reserve balances.

Expenses associated with remediation activities in the Wind Energy segment 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.

Certain of our operating companies sell products to consumers that could be subject to recall.

Certain of our operating companies sell products to consumers that could be subject to recall due to product defect or other safety concerns. If such a recall were to occur, it could have a negative impact on our consolidated results of operations and financial position.

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

The profitability and success of our wind energy, construction or manufacturing companies require us to identify, estimate and timely bid on profitable projects. The quantity and quality of projects up for bids at any time is uncertain. Additionally, once a project 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 could lead to adverse financial results and could lead to the possibility of delay or liquidated damages.

We rely on our information systems to conduct our business, and failure to protect these systems against security breaches 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.

The efficient operation of our business is dependent on computer hardware and software systems. Information systems are vulnerable to security breach by computer hackers and cyber terrorists. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information maintained on our information systems. However, these measures and technology may not adequately prevent security breaches. 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 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.

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.

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 challenges at the 7th Circuit U.S. Court of Appeals, 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.

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 plans to adopt standards of performance for emissions from power plants and refineries by mid-2012. Specific requirements of regulation under the CAA's various programs, and thus their impact on OTP, are uncertain at this time.

WIND ENERGY

Competition from foreign and domestic manufacturers, cost management in a fixed price contract project environment, fluctuations in foreign currency exchange rates and general economic conditions could affect the revenues and earnings of our Wind Energy segment.

Our Wind Energy segment is subject to risks associated with competition from foreign and domestic manufacturers, some of whom have greater distribution capabilities, greater capital resources and other capabilities that may place downward pressure on margins and profitability. Our wind tower manufacturer operates in a fixed price project environment where balancing workload to costs can create variation in margins that may not be recoverable from customers. If DMI is not able to recover cost increases from its customers, it could have a negative effect on profit margins and income from our Wind Energy segment.

Prolonged periods of low utilization of DMI's wind tower production plants, due to a continuing softening of demand for its product, could cause DMI to idle certain facilities. In the fourth quarter 2011, we idled our wind tower production plant in Fort Erie, Ontario. Should this softened demand for wind towers continue, these events may result in impairment charges on certain of DMI's facilities if future cash flow estimates, based on information available to management at the time, indicate that the plants carrying values may not be recoverable or, if any plant assets are sold below their carrying values, significant losses may be incurred.

The U.S. wind industry is reliant on tax and other economic incentives and political and governmental policies. A significant change in these incentives and policies could negatively impact our results of operations and growth.

Our wind tower manufacturing business is focused on supplying towers to wind turbine manufacturers and owners and operators of wind energy generation facilities. The wind industry is dependent on federal tax incentives and state renewable portfolio standards and may not be economically viable absent such incentives.

The federal government provides economic incentives to the owners of wind energy facilities, including a federal production tax credit, an investment tax credit and a cash grant equal in value to the investment tax credit. These programs provide material incentives to develop wind energy generation facilities and thereby impact the demand for our manufactured products and services. The failure of Congress to extend or renew these incentives beyond their current expiration dates could significantly delay the development of wind energy generation facilities and the demand for wind turbines, towers, gearing and related components. We cannot assure that any extension or renewal of the production tax credit, investment tax credit or cash grant program will be enacted prior to its expiration or, if allowed to expire, that any extension or renewal enacted thereafter would be enacted with retroactive effect. Any delay or failure to extend or renew the federal production tax credit, investment tax credit or cash grant program in the future could have a material adverse impact on our business, results of operations and future financial performance.

State renewable energy portfolio standards generally require or encourage state-regulated electric utilities to supply a certain proportion of electricity from renewable energy sources or devote a certain portion of their plant capacity to renewable energy generation. Currently, the majority of states and the District of Columbia have renewable energy portfolio standards in place and certain other states have voluntary utility commitments to supply a specific percentage of their electricity from renewable sources. Any changes to existing renewable energy portfolio standards, the enactment of renewable energy portfolio standards in additional states, or the enactment of a federal renewable energy portfolio may impact the demand for our products. We cannot assure you that government support for renewable energy will continue. The elimination of, or reduction in, state or federal government policies that support renewable energy could have a material adverse impact on our business, results of operations and future financial performance.

We are substantially dependent on a few significant customers in our wind tower manufacturing business.

The wind turbine market in the United States is concentrated, with eight manufacturers controlling in excess of 97% of the market. In addition, the majority of revenues in our wind tower manufacturing business have been highly concentrated with a limited number of customers. These customers were adversely affected by the downturn in the economy and we have seen, and may continue to see, a decrease in order volume from such customers. Among other things, contractual disputes could lead to an overall decrease in such customer's demand for our products and services, difficulty in collecting amounts due for such products or services, or difficulty in collecting amounts due to one or more of our subsidiaries that are not related to the dispute. A material change in payment terms for accounts receivable of a significant customer could have a material adverse effect on our short-term cash flows. We could also experience a reduction in demand if any of our customers determine to become more vertically integrated and produce our products internally. If our relationship with any of our significant customers should change materially, it could be difficult for us to immediately and profitably replace lost sales in a market with such concentration, which would materially adversely affect our results.

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, lumber, concrete, aluminum and resin. 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 97% of our total purchases of PVC resin in 2011 and approximately 98% of our total purchases of PVC resin in 2010. 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.

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, 2011 OTP’s transmission facilities, which are interconnected with lines of other public utilities, consisted of 76 miles of 345 kV lines; 417 miles of 230 kV lines; 862 miles of 115 kV lines; and 3,976 miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of 48 miles of the 345 kV line, with Minnkota Power Cooperative retaining title to the original 230 kV construction. OTP owns an undivided interest in the remaining 345 kV line miles.

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 in each of its nonelectric business segments. The Company’s subsidiaries own construction equipment, tools and facilities and equipment used in: the manufacture of PVC pipe, wind towers and other heavy metal fabricated products, thermoformed products, commercial and waterfront equipment, 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 FEBRUARY 29, 2012)

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 Securities and Exchange Commission. 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, except for Ms. Kommer, who was attending law school prior to 2007 and was employed by the Company as an in-house attorney from 2007 until she was named Vice President of Human Resources in 2009.

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
Edward J. McIntyre (61)	9/8/11	Present:	President and Chief Executive Officer
George A. Koeck (59)	4/10/00	Present:	Senior Vice President, General Counsel and Corporate Secretary
Kevin G. Moug (52)	4/9/01	Present:	Chief Financial Officer and Senior Vice President
Michelle L. Kommer (39)	4/12/10	Present:	Senior Vice President of Human Resources
Charles S. MacFarlane (47)	5/1/03	Present:	President, Otter Tail Power Company
Shane N. Waslaski (36)	4/11/11	Present:	Senior Vice President Manufacturing & Infrastructure Platform

On September 8, 2011, on the resignation of John Erickson as President and Chief Executive Officer, 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, 61, is retired Vice President and former Chief Financial Officer of energy company Xcel Energy, Inc. He has been an independent small-business owner and a member of the Board of Directors since 2006.

With the exception of Charles S. MacFarlane and Shane N. Waslaski, 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. Mr. MacFarlane and Mr. Waslaski are not appointed by the Board of Directors. There are no family relationships between any of the executive officers or directors.

Item 4.MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

The Company's common stock is traded on the NASDAQ Global Select Market under the NASDAQ symbol "OTTR". The information required by this Item can be found on Page 40 of this Annual Report on Form 10-K under the heading "Selected Financial Data," on Page 101 under the heading "Retained Earnings Restriction" and on Page 121 under the heading "Quarterly Information."

Unregistered Sales of Equity Securities

The Company does not have a publicly announced stock repurchase program. The Company did not repurchase any equity securities during the fourth quarter of the fiscal year ended December 31, 2011. The following table shows common shares that were surrendered to the Company by employees to pay taxes in connection with shares issued for incentive awards under the Company's 1999 Stock Incentive Plan during the quarter ended December 31, 2011:

Calendar Month	Total Number of Shares Purchased	Average Price Paid per Share
October 2011	--	--
November 2011	--	--
December 2011	48,628	$ 21.193
Total	48,628	

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 30, 2006, and reinvestment of all dividends).

	2006	2007	2008	2009	2010	2011
OTC	$100.00	$114.96	$80.56	$90.55	$87.07	$89.97
EEI	$100.00	$116.56	$86.37	$95.62	$102.34	$122.80
NASDAQ	$100.00	$108.47	$66.35	$95.38	$113.19	$113.81

Item 6. SELECTED FINANCIAL DATA

(thousands, except number of shareholders and per-share data)	2011	2010	2009	2008	2007
Revenues					
Electric	$342,727	$344,379	$314,666	$340,075	$323,591
Wind Energy	201,921	143,603	160,695	248,994	184,376
Manufacturing	227,116	175,986	161,194	218,302	