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 CO2–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 CO2 emissions in the United States and globally. OTP is an owner or part-owner of three baseload, coal-fired electricity generating plants and three fuel-oil or natural gas-fired combustion turbine peaking plants with a combined generating capability of 679 MW. In 2011, these plants emitted approximately 4.0 million tons of CO2.

OTP monitors and evaluates the possible adoption of national, regional, or state climate change and GHG legislation or regulations that would affect electric utilities. 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, is uncertain.

In April 2007, however, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate CO2 and other GHGs from automobiles as “air pollutants” under the CAA. The Supreme Court 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 CO2 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	194,347
Construction	184,657	134,222	103,831	157,053	150,721
Plastics	123,669	96,945	80,208	116,452	149,012
Corporate Revenues and Intersegment Eliminations	(2,240)	(2,944)	(1,902)	(2,540)	(1,730)
Total Operating Revenues	$1,077,850	$892,191	$818,692	$1,078,336	$1,000,317
Net Income (Loss) from Continuing Operations	$17,120	$(10,826)	$24,639	$33,340	$46,947
Net (Loss) Income from Discontinued Operations	(30,363)	9,482	1,392	1,785	7,014
Net Income (Loss)	$(13,243)	$(1,344)	$26,031	$35,125	$53,961
Operating Cash Flow from Continuing Operations	$79,696	$94,051	$154,624	$104,167	$71,141
Operating Cash Flow - Continuing and Discontinued Operations	104,383	105,017	162,750	111,321	84,812
Capital Expenditures - Continuing Operations	73,677	61,549	171,761	257,266	152,657
Total Assets	1,700,522	1,770,555	1,754,678	1,692,587	1,454,754
Long-Term Debt	471,915	433,676	434,112	337,462	340,362
Basic Earnings (Loss) Per Share - Continuing Operations (1)	0.46	(0.32)	0.67	1.03	1.56
Basic Earnings (Loss) Per Share - Total (1)	(0.40)	(0.06)	0.71	1.09	1.79
Diluted Earnings (Loss) Per Share - Continuing Operations (1)	0.45	(0.32)	0.67	1.03	1.55
Diluted Earnings (Loss) Per Share - Total (1)	(0.40)	(0.06)	0.71	1.09	1.78
Return on Average Common Equity	(2.3)%	(0.3)%	3.8%	6.0%	10.5%
Dividends Declared Per Common Share	1.19	1.19	1.19	1.19	1.17
Dividend Payout Ratio	—	—	168%	109%	66%
Common Shares Outstanding - Year End	36,102	36,003	35,812	35,385	29,850
Number of Common Shareholders (2)	14,687	14,848	14,923	14,627	14,509

(1) Based on average number of shares outstanding.
(2) Holders of record at year end.

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

OVERVIEW

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

Our strategy is to continue to grow our largest business, the regulated electric utility and look for further realignment of our nonelectric business portfolio to lower our overall risk, create a more predictable earnings stream, improve our credit quality and preserve our ability to fund the dividend. Over time, we expect the electric utility business will provide approximately 75% to 85% of our overall earnings. We expect our nonelectric businesses will provide 15% to 25% of our earnings, and will continue to be a fundamental part of our strategy.

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

Our strategy focuses on realigning our portfolio of businesses and refocusing our capital investment in the electric utility. In 2011, in execution of our announced strategy, we sold IPH, our Food Ingredient Processing business, and Wylie, our trucking company headquartered in West Fargo, North Dakota, which was included in our Wind Energy segment. In January 2012, we sold the assets of Aviva, a wholly owned subsidiary of the Company’s waterfront equipment manufacturer that sells a variety of recreational equipment. In February 2012, we entered into an agreement to sell DMS, our Health Services business, with an expected closing date of February 29, 2012. As a result of these 2011 and 2012 transactions, our business structure no longer includes Health Services or Food Ingredient Processing segments, and now includes the remaining five segments listed above.

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

- a threshold level of net earnings and a return on invested capital in excess of our weighted average cost of capital,
- a strategic differentiation from competitors and a sustainable cost advantage,
- a stable or growing industry,
- an ability to quickly adapt to changing economic cycles, and
- a strong management team committed to operational excellence.

Major growth strategies and initiatives in our future include:

Planned capital budget expenditures of up to $846 million for the years 2012 through 2016 of which $730 million are for capital projects at Otter Tail Power Company (OTP), including $265 million for OTP's share of a new air quality control system at Big Stone Plant and $226 million for anticipated expansion of transmission capacity including $118 million for Multi-Value transmission projects and $98 million for CapX2020 transmission projects. See "Capital Requirements" section for further discussion.

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

The continued investigation and evaluation of organic growth opportunities.

In 2011:

Our net cash from continuing operations was $79.7 million.

Our net cash from continuing and discontinued operations was $104.4 million.

Our Electric segment net income increased 12.5% to $38.9 million.

Our Plastics segment net income increased 131.1% to $5.8 million.

Our Manufacturing segment recorded net income of $7.6 million compared with a net loss of $14.0 million in 2010. Manufacturing net loss in 2010 included a $15.4 million net-of-tax asset impairment charge at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment manufacturer. BTD's net income improved by $3.1 million in 2011 compared with 2010.

Our Wind Energy segment lost $21.9 million. DMI Industries, Inc., (DMI), our manufacturer of wind towers, recorded increased costs in the first half of 2011 related to productivity losses due to rework and underutilization of plant capacity and outsourced quality control costs and a $3.1 million pre-tax asset impairment charge related to the idling of its Fort Erie, Ontario plant in the fourth quarter of 2011. DMI's operating loss for the second half of 2011, including the $3.1 million asset impairment charge, was $8.3 million less than in the second half of 2010. The reduction in operating losses for the comparable six-month periods was the result of improved productivity, stabilized production, more efficient resource allocation and elimination of the need for outsourced quality assurance staffing.

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

(in thousands)		2011		2010
Operating Revenues:				
Electric	$	342,505	$	344,146
Nonelectric		735,345		548,045
Total Operating Revenues	$	1,077,850	$	892,191
Net Income (Loss) From Continuing Operations:				
Electric	$	38,886	$	34,557
Nonelectric		(10,673)		(34,122)
Corporate		(11,093)		(11,261)
Total Net Income (Loss) From Continuing Operations:	$	17,120	$	(10,826)

The 20.8% increase in consolidated revenues in 2011 compared with 2010 reflects increased revenue from all segments except Electric, which decreased $1.6 million. Revenues from our Wind Energy segment increased $58.3 million due to a 28% increase in wind tower production. Revenues from our Manufacturing segment increased $51.1 million as a result of higher sales volume due to improved customer demand for the products and services provided by our manufacturing companies. Revenues from our Construction segment increased $50.4 million as improving economic conditions in this segment have resulted in an increase in volume of jobs in progress. Revenues increased by $26.7 million in our Plastics segment as a result of a combination of higher polyvinyl chloride (PVC) pipe prices and increased sales volume.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2011, 2010 and 2009, followed by a discussion of our financial position at the end of 2011 and our outlook for 2012.

RESULTS OF OPERATIONS

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

Intersegment Eliminations—Amounts presented in the following segment tables for 2011, 2010 and 2009 operating revenues, cost of goods sold and other nonelectric operating expenses will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations (in thousands)	2011	2010	2009
Operating Revenues:			
Electric	$ 222	$ 233	$ 194
Nonelectric	2,018	2,711	1,708
Cost of Goods Sold	1,904	2,002	1,463
Other Nonelectric Expenses	336	942	439

ELECTRIC

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

(in thousands)	2011	% change	2010	% change	2009
Retail Sales Revenues	$304,181	--	$305,146	8	$282,116
Wholesale Revenues – Company Generation	14,518	(28)	20,053	59	12,579
Net Revenue – Energy Trading Activity	2,319	(26)	3,144	(1)	3,183
Other Revenues	21,709	35	16,036	(4)	16,788
Total Operating Revenues	$342,727	--	$344,379	9	$314,666
Production Fuel	69,017	(6)	73,102	23	59,387
Purchased Power – System Use	43,451	(3)	44,788	(15)	52,942
Other Operation and Maintenance Expenses	115,863	3	112,174	5	106,457
Asset Impairment	470	--	--	--	--
Depreciation and Amortization	40,283	--	40,241	9	36,946
Property Taxes	10,190	9	9,364	6	8,853
Operating Income	$63,453	(2)	$64,710	29	$50,081

Electric kwh Sales (in thousands)	2011	% change	2010	% change	2009
Retail kwh Sales	4,291,637	1	4,262,748	--	4,244,377
Wholesale kwh Sales – Company Generation	510,978	(18)	624,153	55	402,498
Wholesale kwh Sales – Purchased Power Resold	122,430	(64)	336,875	(66)	1,004,916

2011 compared with 2010

Retail sales revenues decreased by $1.0 million as a result of:

- a $3.1 million reduction in fuel cost recovery revenues related to lower fuel and purchased power costs,
- a $0.8 million decrease in accrued and recovered Conservation Improvement Program (CIP) revenues and incentives, and
- a $0.6 million reduction in Minnesota retail revenues related to an increase in rates that was more than offset by a refund of excess amounts collected under interim rates in effect from June 2010 through September 2011.

These decreases in retail revenue were mostly offset by:

a $2.0 million increase in revenue related to a 0.7% increase in kilowatt-hour (kwh) sales,

a $0.8 million increase in revenues related to the recovery of the North Dakota portion of Big Stone II plant abandonment costs, and

a $0.7 million increase in renewable resource and transmission cost recovery revenues related to an increase in transmission costs eligible for recovery under Minnesota and North Dakota transmission cost recovery riders.

Wholesale electric revenues from company-owned generation decreased $5.5 million due to an 18.1% decline in wholesale kwh sales combined with an 11.6% decrease in the average price per wholesale kwh sold. This was the result of an 8.2% reduction in kwh generation at OTP's generating units related to a scheduled major maintenance shutdown at Big Stone Plant, lower demand in wholesale markets and low natural gas prices. Net gains from energy trading activities, including net mark-to-market gains on forward energy contracts, decreased $0.8 million mainly as a result of a decrease in mark-to-market gains on open energy contracts, in part due to a reduction in trading activity.

Other electric operating revenues increased $5.7 million as a result of: (1) a $3.5 million increase in transmission tariff revenues as a result of increased use of company-owned transmission assets by others, (2) $1.1 million payment received by Otter Tail Energy Services Company (OTESCO) in the first quarter of 2011 for the sale of access rights through an OTESCO wind farm development site, and (3) a $1.1 million refund in 2010 of revenues collected from OTP's Big Stone II project partners in years prior to 2010.

The $4.1 million decrease in fuel costs reflects a 10.7% decrease in kwhs generated from OTP's steam-powered and combustion turbine generators, partially offset by a 5.7% increase in the cost of fuel per kwh generated. The decrease in kwh generation was due to a scheduled major maintenance shutdown of Big Stone Plant in fall 2011. The cost of purchased power for retail sales decreased $1.3 million as a result of a 13.7% decrease in the cost per kwh purchased, despite a 12.4% increase in kwhs purchased for system use.

Electric operating and maintenance expenses increased $3.7 million due to the following:

- a $1.7 million increase in transmission tariff charges related to the increase in kwhs purchased from other generators to serve retail customers,
- a $1.0 million increase in labor costs related to increased health benefit costs,
- a $1.0 million increase in generation plant maintenance costs related to the Big Stone Plant overhaul in fall 2011 and increased maintenance costs at the Langdon wind farm and Coyote Station,
- a $0.9 million increase in expense related to the amortization of the North Dakota portion of Big Stone II plant abandonment costs, which OTP began recovering in August 2010,
- a $0.8 million increase in Minnesota CIP costs related to mandated increases in conservation expenditures in Minnesota, and
- a $0.7 million increase in transportation costs related to increases in gasoline and diesel fuel prices.

These increases in expenses were partially offset by an increase of $2.4 million in administrative and general expenses charged to capital projects in 2011, which decreases expenses charged to operations.

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

Property taxes increased $0.8 million due to valuation increases and increases in local property tax rates on Minnesota property.

2010 compared with 2009
The $23.0 million increase in retail sales revenues was due to the following:

a $7.4 million increase in resource recovery and transmission rider revenues,

a $5.8 million increase in Minnesota CIP surcharge revenues,

a $3.9 million increase in revenues mostly due to a 2.8% increase in kwh sales to retail commercial customers,

a $2.5 million increase from interim rates implemented in Minnesota in June 2010,

a $1.5 million increase related to a South Dakota general rate increase implemented in May 2009,

a $0.8 million increase in FCA revenues related to an increase in fuel and purchased power costs incurred to serve retail customers,

a $0.6 million increase in revenue related to recovery of the North Dakota portion of OTP's Big Stone II plant abandonment costs, and

a $0.5 million increase in revenue related to a Minnesota interim rate refund adjustment in 2009.

The $7.5 million increase in wholesale revenues from company-owned generation was the result of a 55.1% increase in wholesale kwh sales due, in part, to greater plant availability as a result of fewer outages in 2010. Generating plant output, including wind and hydro plants, was 17.8% higher in 2010 than in 2009. Other electric operating revenues decreased $0.8 million, reflecting a $2.4 million reduction in revenues from contracted services, partially offset by a $1.8 million increase in transmission tariff revenues.

The $13.7 million increase in production fuel costs was the result of a 17.2% increase in kwhs generated from OTP's steam-powered and combustion turbine generators, combined with a 5.0% increase in the cost of fuel per kwh generated. Purchased power costs decreased $8.2 million as a result of a 22.7% decrease in kwhs purchased for retail sales, partially offset by a 9.4% increase in the cost per kwh purchased. Both the increase in kwhs generated and the decrease in kwhs purchased were due, in part, to increased plant availability in 2010. Combined fuel and purchased power costs incurred to serve retail customers increased $0.8 million in 2010 compared with 2009, commensurate with the increase in FCA revenues between the years.

The $5.7 million increase in other operation and maintenance expenses was mainly due to the following items: (1) an increase in labor costs of $2.9 million due to increases in wage, benefit and overtime costs and a decrease in labor costs capitalized between the years, (2) a $1.8 million increase in Minnesota CIP recognized program costs commensurate with an increase in CIP retail revenues related to energy efficiency program mandates, (3) a $0.8 million increase in Midwest Independent Transmission System Operator (MISO) charges related to new tariffs initiated in 2010, and (4) amortization of $0.6 million of the North Dakota portion of deferred Big Stone II costs, commensurate with amounts being recovered from retail customers.

The $3.3 million increase in depreciation expense mainly is due to the Luverne Wind Farm turbines placed in service in September 2009.

WIND ENERGY

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

(in thousands)	2011	% change	2010	% change	2009
Operating Revenues	$ 201,921	41	$ 143,603	(11)	$ 160,695
Cost of Goods Sold	196,693	42	138,303	6	130,389
Operating Expenses	11,003	--	10,981	(10)	12,159
Asset Impairment Charge	3,143	--	--	--	--
Depreciation and Amortization	10,845	5	10,363	6	9,777
Operating (Loss) Income	$ (19,763)	(23)	$ (16,044)	(292)	$ 8,370

2011 compared with 2010

DMI's revenues increased $58.3 million as a result of a 28.2% increase in tower production. Cost of goods sold at DMI increased $58.4 million reflecting $56.7 million in increased costs related to the increase in towers produced and $1.1 million in costs mainly related to the absorption of higher steel costs when a supplier did not fulfill its delivery requirements and productivity losses of $0.6 million due to rework and underutilization of plant capacity and outsourced quality control costs to satisfy expanded customer requirements. DMI temporarily idled its Fort Erie plant in the fourth quarter, as the plant had completed all of its current tower orders. After the Ontario provincial election in October 2011, DMI received and is working on numerous requests for quotes for towers and capacity in the 2012-2013 timeframe given the certainty the election brought to the Green Energy Act staying in place. DMI currently does not have orders booked for its Fort Erie facility for 2012 and does not intend to reopen the plant until sufficient orders are received of such a magnitude as to justify a start up. DMI does not expect to be able to recover the current book value of its Fort Erie plant and equipment and, accordingly, recorded a $3.1 million asset impairment charge based on independent appraisals of the current market value of the facility. Depreciation expense increased mainly as a result of capital additions at DMI in 2011.

2010 compared with 2009

DMI’s revenues decreased $17.1 million as lower production levels were realized due to a different customer mix and lower productivity while supporting deliveries on a customer contract. Cost of goods sold at DMI increased $7.9 million. A reduction in costs related to production decreases was offset by $16.6 million in additional production costs incurred in 2010 to complete towers to a customer’s new design specifications and to support the customer’s delivery schedule for completed towers. Operating expenses at DMI decreased $1.2 million as DMI recorded a $0.9 million loss on the sale of fixed assets in 2009 compared to no losses on asset sales in 2010. Also, DMI’s insurance expenses decreased $0.4 million as a result of safety improvements. Depreciation expense increased mainly as a result of 2009 capital additions.

MANUFACTURING

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

(in thousands)	2011	% change	2010	% change	2009
Operating Revenues	$ 227,116	29	$ 175,986	9	$ 161,194
Cost of Goods Sold	175,122	33	131,207	2	128,216
Other Operating Expenses	23,071	(11)	26,006	5	24,734
Asset Impairment Charge	--	--	19,251	--	--
Depreciation and Amortization	12,936	1	12,819	1	12,650
Operating Income (Loss)	$ 15,987	220	$ (13,297)	(202)	$ (4,406)

2011 compared with 2010

The increase in revenues in our Manufacturing segment in 2011 compared with 2010 relates to the following:

Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, increased $44.7 million (42.1%) as a result of higher sales volume due to improved customer demand for products and services.

Revenues at ShoreMaster increased $4.7 million (14.4%) as a result of a $2.4 million increase in commercial sales related to work completed on a large marina project in 2011 and increased sales of residential products due to ShoreMaster expanding its dealer network by 39 dealers and implementing new products in 2011. New product sales contributed $1.5 million to ShoreMaster’s increase in revenues.

Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased by $1.7 million (4.6%) mainly as a result of increased sales of horticultural products.

The increase in cost of goods sold in our Manufacturing segment in 2011 compared with 2010 consists of the following:

Cost of goods sold at BTD increased $37.3 million mainly as a result of increased sales volume.

Cost of goods sold at ShoreMaster increased $5.0 million related to increases in product sales and warranty accruals combined with cost overruns on a large commercial marina project.

Cost of goods sold at T.O. Plastics increased $1.6 million as a result of the increase in sales of horticultural products combined with higher material costs related to price increase for resin.

The decrease in other operating expenses in our Manufacturing segment in 2011 compared with 2010 relates to the following:

Operating expenses at BTD increased $1.9 million mainly due to increased salary and benefit costs related to workforce expansion to support the increase in revenues between the years.

Operating expenses at ShoreMaster decreased $5.0 million, reflecting a $2.9 million reduction in bad debt expense, a $0.8 million decrease in sales and marketing expenses, a $0.5 million decrease in benefit expenses, a $0.4 million decrease in professional services and a $0.2 million reduction in research and development costs.

Operating expenses at T.O. Plastics increased $0.2 million due to increased salary and benefit costs and insurance costs offset by a reduction in advertising expenses.

2010 compared with 2009

The increase in revenues in our Manufacturing segment in 2010 compared with 2009 relates to the following:

Revenues at BTD increased $21.6 million (25.6%) due to improved customer demand and higher scrap-metal prices in 2010.

Revenues at ShoreMaster decreased $9.0 million (21.5%) due to an $11.8 million decrease in commercial sales, partially offset by a $2.8 million increase in sales of residential products.

Revenues at T.O. Plastics increased $2.2 million (6.4%) due to increased sales of horticultural and custom products.

The increase in cost of goods sold in our Manufacturing segment in 2010 compared with 2009 consists of the following:

Cost of goods sold at BTD increased $11.3 million as a result of a $16.2 million increase in labor, material and overhead costs related to higher sales volumes, mitigated by a $4.9 million reduction in costs due to productivity improvements and sales of higher cost finished goods inventory in the first quarter of 2009.

Cost of goods sold at ShoreMaster decreased $8.7 million mainly due to the decrease in sales of commercial products, but also due to $1.8 million in additional costs incurred on a commercial project in 2009.

Cost of goods sold at T.O. Plastics increased $0.4 million as a result of a $1.6 million increase in labor, material and overhead costs related to higher sales volumes, mitigated by a $1.2 million reduction in costs due to productivity improvements.

The increase in other operating expenses in our Manufacturing segment in 2010 compared with 2009 relates to the following:

Other operating expenses at BTD decreased $0.3 million mainly as a result of reductions in outside sales commissions paid in 2010.

Other operating expenses at ShoreMaster increased $1.0 million between the periods mainly due to an increase in its provision for uncollectible accounts in 2010.

Other operating expenses at T.O. Plastics increased $0.6 million mainly due to increased salary and benefit costs related to new hires in engineering and sales positions and to an increase in promotional expenses.

Asset Impairment Charge—In light of continuing economic uncertainty and delayed economic recovery, ShoreMaster revised its sales and operating cash flow projections downward in the second quarter of 2010, which resulted in a reassessment of the carrying value of its recorded goodwill. The fair value determination indicated ShoreMaster's goodwill and other intangible assets were 100% impaired and its long-lived assets were partially impaired, resulting in the following impairment charges in June 2010:

(in thousands)	
Goodwill	$ 12,259
Brand/Trade Name	4,786
Other Intangible Assets	140
Long-Lived Assets	2,066
Total Asset Impairment Charges	$ 19,251

CONSTRUCTION

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

(in thousands)	2011	% change	2010	% change	2009
Operating Revenues	$184,657	38	$134,222	29	$103,831
Cost of Goods Sold	173,654	44	120,470	36	88,429

Operating Expenses	11,886	(3)	12,235	8	11,311
Depreciation and Amortization	2,009	(1)	2,023	1	2,010
Operating (Loss) Income	$(2,892)	(472)	$(506)	(124)	$2,081

2011 compared with 2010

The increase in revenues in our Construction segment in 2011 compared with 2010 relates to the following:

Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, increased $48.7 million (52.3%) due to an increase in construction activity.

Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, increased $1.7 million (4.1%) mainly due to increased revenue from electrical and data wiring work.

The increase in cost of goods sold in our Construction segment in 2011 compared with 2010 relates the following:

Cost of goods sold at Foley increased $51.9 million, mainly in the areas of material and subcontractor costs related to the increase in Foley's work volume between the periods.

Cost of goods sold at Aevenia increased $1.3 million between the periods, primarily in labor costs, as a result of increased electrical and data wiring work and the reporting of indirect labor costs in cost of goods sold in 2011 as compared to other operating expenses in 2010.

The decrease in other operating expenses in our Construction segment in 2011 compared with 2010 relates to the following:

Operating expenses at Foley increased $1.0 million between the periods mainly for salaries and benefits in order to support the increase in project growth.

Operating expenses at Aevenia decreased $1.4 million as a result of indirect labor costs being recorded in costs of goods sold in 2011 instead of operating expense, an increase in gains on sales of assets and a decrease in outside legal services.

2010 compared with 2009

The increase in revenues in our Construction segment in 2010 compared with 2009 relates to the following:

Revenues at Foley increased $29.0 million (45.3%) due to an increase in construction activity.

Revenues at Aevenia increased $1.4 million (3.5%) as a result of an increase in electrical underground and substation work, partially offset by reductions in work on overhead line construction and wind generation projects in 2010.

The increase in cost of goods sold in our Construction segment in 2010 compared with 2009 relates to the following:

Cost of goods sold at Foley increased $30.2 million as a result of an increase in the size and volume of jobs in progress in 2010.

Cost of goods sold at Aevenia increased $1.8 million, mainly due to an increase in work volume.

The increase in other operating expenses in our Construction segment in 2010 compared with 2009 relates to the following:

Operating expenses at Foley increased $0.7 million between the periods mainly for salaries, maintenance and insurance.

Operating expenses at Aevenia increased $0.2 million due to a decrease in gains on sales of assets and an increase in advertising and promotional expenses in 2010.

PLASTICS

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

(in thousands)		2011	% change		2010	% change		2009
Operating Revenues	$	123,669	28	$	96,945	21	$	80,208
Cost of Goods Sold		103,131	24		82,866	15		71,872
Operating Expenses		6,210	20		5,174	9		4,764
Depreciation and Amortization		3,377	(2)		3,430	16		2,945
Operating Income	$	10,951	100	$	5,475	773	$	627

2011 compared with 2010
The $26.7 million increase in Plastics operating revenues in 2011 compared with 2010 was due to a 10.7% increase in pounds of PVC pipe sold combined with a 15.2% increase in the price per pound of PVC pipe sold driven by an increase in resin prices. The $20.3 million increase in cost of goods sold was related to the increase in pounds of PVC pipe sold combined with a 12.4% increase in the cost per pound of pipe sold, which was also driven by the increase in PVC resin prices. The increase in operating expenses is due to increased labor costs and in commissions paid to independent sales representatives.

2010 compared with 2009
The $16.7 million increase in Plastics operating revenues in 2010 compared with 2009 was due to a 4.1% increase in pounds of PVC pipe sold combined with a 16.2% increase in the price per pound of PVC pipe sold driven by an increase in resin prices. The $11.0 million increase in cost of goods sold was related to the increase in pounds of PVC pipe sold combined with a 10.7% increase in the cost per pound of pipe sold, which was also driven by the increase in PVC resin prices. The increased profitability between the years was also impacted by the sell-off of higher priced finished goods inventory in the first quarter of 2009. Expenses incurred in 2010 in connection with the planned relocation of production equipment from Hampton, Iowa to Fargo, North Dakota contributed to the $0.4 million increase in operating expenses. Asset additions in 2009 and the acceleration of amortization of leasehold improvements at the Hampton facility in 2010 contributed to the $0.5 million increase in depreciation and amortization expense between the years.

CORPORATE

Corporate includes items such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of operating segment performance. Corporate is not an operating segment. Rather it is added to operating segment totals to reconcile to totals on our consolidated statements of income.

(in thousands)		2011	% change		2010	% change		2009
Operating Expenses	$	14,897	(5)	$	15,741	19	$	13,246
Depreciation and Amortization		550	5		524	32		397

Corporate operating expenses were higher in 2010 than in 2011 or 2009 as a result of severance costs related to personnel changes offset partially by a reduction in corporate costs allocated to OTP in 2010.

CONSOLIDATED OTHER INCOME

Other income increased $1.7 million in 2011 compared with 2010 due to a $0.9 million increase in Allowance for Funds Used During Construction (AFUDC) and a $0.8 million reduction in the loss related to foreign currency exchange.

Other income decreased $3.6 million in 2010 compared with 2009 as a result of: (1) a $3.2 million decrease in AFUDC related to a decrease in construction work in progress at OTP as a result of not having a major project under construction in 2010 similar to the Luverne Wind Farm project in 2009, (2) a $0.7 million increase in foreign currency exchange loss and (3) a $0.2 million goodwill impairment write off related to a reduction in the fair value of a mechanical and HVAC contracting firm owned by OTESCO offset by a $0.5 million increase in interest income.

CONSOLIDATED INTEREST CHARGES

Interest charges decreased $1.1 million in 2011 compared with 2010 due to a $0.6 reduction in the amortization of debt issuance expense and reacquisition losses and a $0.5 million increase in capitalized interest charges related to an increase in construction work in progress between the years.

Interest charges increased $8.5 million in 2010 compared with 2009, mainly as a result of the issuance of $100 million of 9.000% Notes due 2016 in December 2009. This contributed $8.4 million to the increase in interest expenses. A reduction in interest expense of $1.7 million related to the retirement of the $75 million in debt incurred in May 2009 to finance construction of OTP's 33 wind turbines at the Luverne Wind Farm was more than offset by a $1.2 million reduction in capitalized interest charges related to a reduction in construction work in progress and a $0.7 million increase in amortization of debt issuance expenses and reacquisition losses between the years.

CONSOLIDATED INCOME TAXES

The $3.1 million increase in Income Tax Expense (Benefit) – Continuing Operations between 2011 and 2010 is due, in part, to a $31.0 million increase in income from continuing operations before income taxes between the years. The Company's effective tax rate on income from continuing operations in 2011 was 10.9% compared with 8.3% in 2010. In 2011, the Company's effective tax rate was less than the composite statutory rate mainly as a result of recording $7.3 million in federal production tax credits, partially offset by not recognizing $3.7 million in tax savings on operating losses from DMI's Canadian operations. In 2010, the Company's effective tax rate was less than the composite statutory rate mainly as a result of: (1) recording a $5.5 million valuation allowance against deferred tax assets related to tax operating loss carryforwards of DMI's Canadian operations, (2) not recording any tax savings on $9.4 million of ShoreMaster's goodwill impairment, and (3) a $1.1 million reversal of deferred tax assets at DMI related to a reduction in Canadian statutory tax rates, partially offset by (4) $6.4 million in federal production tax credits taken in 2010.

The $4.3 million decrease in income tax benefit in 2010 compared with 2009 reflects: (1) the establishment of a $5.5 million valuation allowance against deferred tax assets related to tax operating loss carryforwards of DMI's Canadian operations, (2) a $3.1 million reduction in 2009 income taxes related to a permanent difference in the depreciable tax value of OTP's Luverne Wind Farm assets, (3) a $1.7 million charge to income tax expense related to a change in the tax treatment of postretirement prescription drug benefits under 2010 federal healthcare legislation, and (4) a $1.1 million reversal of deferred tax assets at DMI related to a reduction in Canadian statutory tax rates, offset by (5) a $6.2 million increase in taxable income between the years. Although our income before income taxes decreased in 2010 compared with 2009, $9.4 million of ShoreMaster's 2010 goodwill impairment and a $3.2 million reduction in the electric segment's AFUDC income generated no tax savings in 2010.

Federal production tax credits are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. Income tax reductions from federal production tax credits are passed back to OTP's retail electric customers through reductions to renewable resource recovery riders or renewable energy costs recovered in general rates.

DISCONTINUED OPERATIONS

On May 6, 2011, we completed the sale of IPH for approximately $87.0 million in cash. The proceeds from the sale, net of $3.0 million deposited in an escrow account, were used to pay down borrowings under our existing credit agreement. In the second half of 2011, the IPH sales proceeds were reduced by $1.2 million related to a purchase price adjustment. On December 29, 2011, we completed the sale of Wylie, our trucking business, for approximately $25.0 million in cash. The proceeds from the sale of Wylie will be used for general corporate purposes. On January 18, 2012, we sold the assets of Aviva, a wholly owned subsidiary of the Company's waterfront equipment manufacturer that sells a variety of recreational equipment, for $0.3 million in cash. On February 6, 2012 we entered into an agreement to sell DMS for $30.0 million in cash. The sale of DMS is subject to standard closing conditions and is expected to be finalized by February 29, 2012. As a result of the pending sale of DMS, a $39.1 million net-of-tax impairment charge was recorded to reflect the write down of DMS to its fair value based on the indicated sales price.

The results of operations of IPH, Wylie, Aviva and DMS are reported as discontinued operations in our consolidated statements of income for the years ended December 31, 2011, 2010 and 2009 as summarized in the table below:

	For the Year Ended December 31, 2011					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany transactions adjustment	Total
Operating Revenues	$ 28,125	$ 49,884	$ 2,206	$ 89,558	$ (4,119)	$ 165,654
Operating Expenses	24,046	55,927	3,976	85,244	(4,119)	165,074
Asset Impairment Charge	--	--	456	56,379	--	56,835
Other Income (Deductions)	(228)	18	(18)	281	(3)	50
Interest Expense	11	709	379	1,726	(2,772)	53
Income Tax Expense (Benefit)	1,462	(2,683)	(1,050)	(16,058)	1,108	(17,221)
Net Income (Loss) from Operations	2,378	(4,051)	(1,573)	(37,452)	1,661	(39,037)
Gain (Loss) on Disposition Before Taxes	15,471	(946)	--	--	--	14,525
Income Tax Expense on Disposition	2,997	2,854	--	--	--	5,851
Net Gain (Loss) on Disposition	12,474	(3,800)	--	--	--	8,674
Net Income (Loss)	$ 14,852	$ (7,851)	$ (1,573)	$ (37,452)	$ 1,661	$ (30,363)

	For the Year Ended December 31, 2010					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany transactions adjustment	Total
Operating Revenues	$ 77,412	$ 54,143	$ 2,704	$ 100,301	$ (3,601)	$ 230,959
Operating Expenses	65,261	52,311	3,200	98,794	(3,601)	215,965
Asset Impairment Charge	--	--	489	--	--	489
Other Income (Deductions)	(326)	8	(10)	331	--	3
Interest Expense	111	522	346	1,289	(2,176)	92
Income Tax Expense (Benefit)	3,716	511	(532)	369	870	4,934
Net Income (Loss)	$ 7,998	$ 807	$ (809)	$ 180	$ 1,306	$ 9,482

	For the Year Ended December 31, 2009					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany transactions adjustment	Total
Operating Revenues	$79,098	$32,228	$2,992	$110,006	$ (3,504)	$220,820
Operating Expenses	66,847	36,476	4,031	113,066	(3,504)	216,916

Product Recall and Testing Costs	--	--	1,625	--	--	1,625
Other Income (Deductions)	(398)	6	(7)	298	--	(101)
Interest Expense	36	282	190	449	(860)	97
Income Tax Expense (Benefit)	4,410	(1,814)	(1,137)	(1,114)	344	689
Net Income (Loss)	$7,407	$(2,710)	$(1,724)	$(2,097)	$ 516	$1,392

Aviva's 2009 expenses included $1.1 million in costs related to the recall of certain trampoline products and $0.5 million in costs to test imported products for lead and phthalate content.

IMPACT OF INFLATION

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

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

LIQUIDITY

The following table presents the status of our lines of credit as of December 31, 2011 and December 31, 2010:

(in thousands)	Line Limit	In Use on December 31, 2011	Restricted due to Outstanding Letters of Credit	Available on December 31, 2011	Available on December 31, 2010
Otter Tail Corporation Credit Agreement	$ 200,000	$ --	$ 1,224	$ 198,776	$ 144,350
OTP Credit Agreement	170,000	--	4,050	165,950	144,436
Total	$ 370,000	$ --	$ 5,274	$ 364,726	$ 288,786

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if needed. Our balance sheet is strong and we are in compliance with our debt covenants. Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings and alternative financing arrangements such as leasing.

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. We expect to file a new shelf registration statement prior to the expiration of our existing shelf registration in May 2012. On March 17, 2010, we entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million. Equity or debt financing will be required in the period 2012 through 2016 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

Our common stock dividend payments have exceeded our net (losses) income in each of the last four years. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share to levels in excess of the indicated annual dividend per share of $1.19, cash flows from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects. The decision to declare a quarterly dividend is reviewed quarterly by the Board of Directors.

DMI is party to a $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement is set to expire in July 2012. We are currently reviewing our options regarding this agreement. The discount rate under the current agreement is the 3-month LIBOR plus 4%. Accounts receivable totaling $72.0 million were sold in 2011 compared with $62.7 million in 2010. Discounts, fees and commissions charged to operating expense for the years ended December 31, 2011 and 2010 were $0.6 million and $0.2 million, respectively. The balance of receivables sold that was outstanding to the buyer as of December 31, 2011 was $27.1 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in our consolidated balance sheets and the proceeds are included in the cash flows from operating activities in our consolidated statement of cash flows.

Cash provided by operating activities from continuing operations was $79.7 million in 2011 compared with $94.1 million in 2010. Cash provided by operating activities from continuing operations decreased $14.4 million in 2011 compared with 2010, despite a $27.9 million increase in net income from continuing operations in 2011 over 2010 and a $20 million discretionary contribution to our pension plan in 2010, mainly as a result of receiving $54.3 million in tax refunds in 2010 compared with just $0.3 million in tax refunds in 2011. In May 2010 we received a federal income tax refund of $42.3 million related to the carry-back of 2009 net operating losses for tax to prior years.

Net cash used in investing activities of continuing operations was $71.1 million in 2011 compared to $63.4 million in 2010. The $7.7 million increase in cash used for investing activities includes a $12.1 million increase in cash used for capital expenditures, offset by a $1.6 million increase in proceeds from the sale of noncurrent assets and a $2.8 million decrease in cash used for investments. Cash used for capital expenditures increased $7.1 million at OTP, mainly related to expenditures for the Bemidji to Grand Rapids and Fargo to St. Cloud CapX2020 transmission line projects. Cash used for capital expenditures increased $4.1 million at BTD, mainly related to equipment purchases and building renovations to accommodate the new equipment.

Net cash used in financing activities from continuing operations increased $68.9 million in 2011 compared with 2010. In 2010 we increased short-term borrowings and checks issued in excess of cash by $80.4 million and in 2011 we repaid $88.0 million in short-term borrowings and checks issued in excess of cash. In 2011, net proceeds of $84.3 million from the sale of IPH were used to pay down short-term debt. In 2010, OTP paid off the remaining $58.0 million balance outstanding on its two-year, $75.0 million term loan that was originally due on May 20, 2011, using lower costs funds available under the OTP Credit Agreement. In December 2011, OTP issued $140 million in long-term debt and used a portion of the proceeds to retire its $90 million Senior Notes due December 1, 2011, and to retire early its $10.4 million in pollution control refunding revenue bonds due December 1, 2012. OTP used the remaining proceeds to repay its outstanding short-term debt, to pay fees and expenses related to its $140 million debt issuance and to fund a $10 million contribution to the Company’s pension plan in January 2012.

CAPITAL REQUIREMENTS

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

Cash used for consolidated capital expenditures was $74 million in 2011, $62 million in 2010 and $172 million in 2009. Estimated capital expenditures for 2012 are $137 million. Total capital expenditures for the five-year period 2012 through 2016 are estimated to be approximately $846 million, which includes $265 million for OTP's share of a new air quality control system at Big Stone Plant 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 breakdown of 2009, 2010 and 2011 actual cash used for capital expenditure and 2012 through 2016 estimated capital expenditures by segment is as follows:

(in millions)	2009	2010	2011	2012	2012-2016
Electric	$ 146	$ 43	$ 50	$ 117	$730
Wind Energy	11	3	6	5	23
Manufacturing	8	7	11	10	69
Construction	2	5	3	3	14
Plastics	4	3	2	2	10
Corporate	1	1	2	--	--
Total	$ 172	$ 62	$ 74	$ 137	$846

The following table summarizes our contractual obligations at December 31, 2011 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-Term Debt Obligations	$ 475	$ 3	$ 1	$ 100	$ 371
Interest on Long-Term Debt Obligations	302	31	62	61	148
Capacity and Energy Requirements	174	33	45	22	74
Coal Contracts (required minimums)	87	52	21	14	--
Postretirement Benefit Obligations	78	4	8	9	57
Operating Lease Obligations	51	9	12	10	20
Other Purchase Obligations	41	41	--	--	--
Total Contractual Cash Obligations	$ 1,208	$ 173	$ 149	$ 216	$ 670

Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan as we are not currently required to make a contribution to that plan.

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings, and alternative financing arrangements such as leasing. Equity or debt financing will be required in the period 2012 through 2016 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. We expect to file a new shelf registration statement prior to the expiration of our existing shelf registration in May 2012.

On March 17, 2010, we entered into a Distribution Agreement (the Agreement) with JPMS. Pursuant to the terms of the Agreement, we may offer and sell our common shares from time to time through JPMS, as our distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75,000,000. Under the Agreement, we will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. We are not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to our shelf registration statement, as amended. No shares have been sold pursuant to the Agreement.

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2011 and December 31, 2010:

(in thousands)	Line Limit	In Use on December 31, 2011	Restricted due to Outstanding Letters of Credit	Available on December 31, 2011	Available on December 31, 2010
Otter Tail Corporation Credit Agreement	$ 200,000	$ --	$ 1,224	$ 198,776	$ 144,350
OTP Credit Agreement	170,000	--	4,050	165,950	144,436
Total	$ 370,000	$ --	$ 5,274	$ 364,726	$ 288,786

Under the Otter Tail Corporation Credit Agreement, the maximum amount of debt outstanding in 2011 was $112,945,000 on April 22, 2011 and the average daily balance of debt outstanding during 2011 was $40,624,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2011 was 3.7% compared with 3.4% in 2010. Under the OTP Credit Agreement, the maximum amount of debt outstanding in 2011 was $30,672,000 on February 18, 2011 and the average daily balance of debt outstanding during 2011 was $16,087,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2011 was 1.5% compared with 0.8% in 2010.

On May 4, 2010 we entered into a $200 million Second Amended and Restated Credit Agreement (the Credit Agreement), which is an unsecured revolving credit facility that we can draw on to support our nonelectric operations. Borrowings under the Credit Agreement bear interest at LIBOR plus 3.25%, subject to adjustment based on our senior unsecured credit ratings. The Credit Agreement expires on May 4, 2013. The Credit Agreement contains a number of restrictions on us and the businesses of Varistar and its material subsidiaries, including restrictions on our and their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Credit Agreement also contains affirmative covenants and events of default. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Credit Agreement are guaranteed by certain of our material subsidiaries. Outstanding letters of credit issued by us under the Credit Agreement can reduce the amount available for borrowing under the line by up to $50 million. The Credit Agreement has an accordion feature whereby the line can be increased to $250 million as described in the Credit Agreement.

On March 3, 2011 OTP entered into an Amended and Restated Credit agreement (the OTP Credit Agreement) that provides for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP’s senior unsecured debt. OTP is required to pay the Banks’ commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower’s credit ratings. The OTP Credit Agreement expires on March 3, 2016.

Long-Term Debt

On December 4, 2009 we issued $100 million of our 9.000% notes due 2016 under the indenture (for unsecured debt securities) dated as of November 1, 1997, as amended by the First Supplemental Indenture dated as of July 1, 2009, between us and U.S. Bank National Association (formerly First Trust National Association), as trustee. The notes are senior unsecured indebtedness and bear interest at 9.000% per year, payable semi-annually in arrears on June 15 and December 15 of each year, beginning June 15, 2010. The entire principal amount of the notes, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016. The net proceeds from the issuance of approximately $98.3 million, after deducting the underwriting discount and offering expenses, were used to repay our revolving credit facility, which had an outstanding balance due of $107.0 million on November 30, 2009 at an interest rate of approximately 2.6%.

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

On December 1, 2011 OTP issued $140 million aggregate principal amount of OTP’s 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes) pursuant to a Note Purchase Agreement dated July 29, 2011 (2011 Note Purchase Agreement) between OTP and the purchasers named therein. OTP used a portion of the proceeds of the 2021 Notes to retire $90 million aggregate principal amount of OTP’s 6.63% Senior Notes due December 1, 2011 and $10.4 million aggregate principal amount of its pollution control refunding revenue bonds due December 1, 2012. The remaining proceeds of the 2021 Notes were used to repay short-term debt of OTP which was issued to fund capital expenditures, to pay fees and expenses related to the debt issuance and to fund a $10 million contribution to the Company’s pension plan in January 2012.

The note purchase agreement relating to our $50 million 8.89% senior note due November 30, 2017, as amended (the Cascade Note Purchase Agreement), the note purchase agreement relating to OTP’s $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037, as amended (the 2007 Note Purchase Agreement) and the 2011 Note Purchase Agreement each states that the applicable obligor may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the applicable obligor to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The 2007 Note Purchase Agreement, the Cascade Note Purchase Agreement and the 2011 Note Purchase Agreement each contain a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor’s ability and the ability of the obligor’s subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Our obligations under the Cascade Note Purchase Agreement are guaranteed by certain of our material subsidiaries. Cascade owned approximately 9.6% of the Company’s outstanding common stock as of December 31, 2011.

On June 23, 2010 we entered into Amendment No. 3 to the Cascade Note Purchase Agreement. Amendment No. 3 amends certain covenants and related definitions contained in the Cascade Note Purchase Agreement to, among other things, provide us and our material subsidiaries with additional flexibility to incur certain customary liens, make certain investments, and give certain guaranties, in each case under the circumstances set forth in Amendment No. 3. On July 29, 2010 we entered into Amendment No. 4 to the Cascade Note Purchase Agreement, which was effective June 30, 2010. The amendments contained in Amendment No. 4 permit us to exclude impairment charges and write-offs of assets from the calculation of the interest charges coverage ratio required to be maintained under the Cascade Note Purchase Agreement. On December 12, 2011 we entered into Amendment No. 5 to the Cascade Note Purchase Agreement which permits us to exclude gains or losses from the sales of subsidiaries.

Financial Covenants
As of December 31, 2011 the Company was in compliance with the financial statement covenants that existed in its debt agreements.

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

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

Under the Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Credit Agreement. As of December 31, 2011 our Interest and Dividend Coverage Ratio calculated under the requirements of the Credit Agreement was 1.70 to 1.00.

Under the Cascade Note Purchase Agreement, we may not permit our ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or our Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement. As of December 31, 2011 our Interest Charges Coverage Ratio calculated under the requirements of the Cascade Note Purchase Agreement was 1.61 to 1.00.

Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the OTP Credit Agreement. As of December 31, 2011 OTP's Interest and Dividend Coverage Ratio calculated under the requirements of the OTP Credit Agreement was 3.30 to 1.00.

Under the 2007 Note Purchase Agreement, 2011 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of December 31, 2011 OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.30 to 1.00.

As of December 31, 2011 our interest-bearing debt to total capitalization was 0.45 to 1.00 on a fully consolidated basis and 0.50 to 1.00 for OTP.

Our ratio of earnings to fixed charges from continuing operations, which includes imputed finance costs on operating leases, was 1.5x for 2011 compared to 0.7x for 2010, and our debt interest coverage ratio before taxes was 1.6x for 2011 compared to 1.6x for 2010. During 2012, we expect these coverage ratios to increase, assuming 2012 net income meets our expectations.

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OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $11.7 million, but our line of credit borrowing limits are only restricted by $5.3 million of the outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2012 BUSINESS OUTLOOK

We anticipate 2012 diluted earnings per share to be in the range of $1.00 to $1.40. This guidance reflects the current mix of businesses owned as we start out 2012. It considers the cyclical nature of some of our businesses and reflects challenges presented by current economic conditions, as well as our plans and strategies for improving future operating results. Our current consolidated capital expenditures expectation for 2012 is in the range of $125 million to $135 million. This compares with $74 million of capital expenditures in 2011. We plan to invest in generation and transmission projects for the Electric segment that have the potential to positively impact our earnings and returns on capital. Future Electric segment projects include the construction of a new air quality control system at Big Stone Plant to meet requirements of the Clean Air Act and regional haze regulations, investment in two MISO-determined ‘multi-value’ transmission projects that will serve the nine-state MISO region, and continuing investment, with other utilities, in three CapX2020 transmission projects already under way.

Segment components of the corporation’s 2012 earnings per share guidance range are as follows:

	EPS Range	
	Low	High
Electric	$ 1.05	$ 1.10
Wind Energy	$ (0.15)	$ 0.00
Manufacturing	$ 0.30	$ 0.35
Construction	$ 0.02	$ 0.07
Plastics	$ 0.06	$ 0.11
Corporate	$ (0.28)	$ (0.23)
Totals	$ 1.00	$ 1.40

Contributing to our earnings guidance for 2012 are the following items:

We expect net income to increase slightly in our Electric segment in 2012 compared with 2011. This is based on new rates being in place in Minnesota for a full year, rider recovery increases and an increase in capitalized interest costs related to larger construction expenditures, offset by lower conservation improvement program incentives and increases in operating and maintenance expenses due to higher benefit costs.

We expect significant improvement in operations from our Wind Energy segment in 2012. DMI has been able to stabilize production, improve productivity, align headcount with current production demands and eliminate the need for outsourced quality assurance staffing. Order backlog will continue to support current plant staffing at DMI’s Tulsa and West Fargo plants. DMI continues to experience increased pricing pressure on new orders due to overcapacity in the U.S. market and significantly lower steel costs available to Asian manufacturers. Potential exposure to liquidated damages, warranty claims, or remediation costs related to past production issues remain. Backlog in the Wind Energy segment is $154 million for 2012 compared with $157 million one year ago.

We expect earnings from our Manufacturing segment to improve in 2012 due to the following factors:

- Increased order volume and continuing improvement in economic conditions in the industries BTD serves
- Improved performance at ShoreMaster as a result of bringing costs in line with current revenue levels, the sale of Aviva and the closure of ShoreMaster's Camdenton, Missouri plant with relocation of Camdenton's commercial production operations to ShoreMaster's Fergus Falls, Minnesota and St. Augustine, Florida facilities
- Stable earnings from T.O. Plastics
- Backlog for the manufacturing companies of approximately $121 million for 2012 compared with $86 million one year ago.

We expect higher net income from our Construction segment in 2012 as it has implemented improved cost control processes in construction management and selectively bid on projects with the potential for higher margins. Backlog in place for the construction businesses is $106 million for 2012 compared with $164 million one year ago.

We expect a slight decrease in Plastics segment net income in 2012.

Corporate general and administrative costs are expected to remain relatively flat between the years.

The sales of IPH, Wylie, Aviva and DMS were strategic decisions by management to monetize assets and divest of companies that do not fit with our current operating plans. The divestitures free up liquidity going forward for upcoming Electric segment capital investments and help ease the need to rely on the capital markets to fully fund these expenditures. We will continue to review our portfolio to see where additional opportunities exist to improve our risk profile, improve credit metrics and generate additional sources of cash to support the future capital expenditure plans of our Electric segment. This will result in a larger percentage of our earnings coming from our most stable and relatively predictable business, OTP, and is consistent with the strategy to grow this business given its current investment opportunities.

The following table shows our 2011 capital expenditures and 2012 through 2016 anticipated capital expenditures and electric utility average rate base:

(in millions)	2011	2012	2013	2014	2015	2016
Capital Expenditures:						
Electric Segment:						
Transmission		$ 47	$ 34	$ 36	$ 50	$ 59
Environmental		31	86	78	70	--
Other		39	50	50	50	50
Total Electric Segment	$ 70	$ 117	$ 170	$ 164	$ 170	$ 109
Nonelectric Segments	24	20	19	25	24	28
Total Capital Expenditures	$ 94	$ 137	$ 189	$ 189	$ 194	$ 137
Total Electric Utility Average Rate Base	$ 653	$ 686	$ 789	$ 904	$ 1,036	$ 1,117

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2012 through 2016 timeframe. We intend to maintain our equity to total capitalization ratio near its present level of 51% in the Electric segment and will seek to earn our authorized overall return on equity of approximately 10.5% in the utility's regulatory jurisdictions.

Regarding the collective operating companies in the nonelectric segments, there is a general expectation that business will strengthen in 2012 and 2013 as the U.S. economy slowly recovers. This is expected to lead to increased demand for our industrial products and services, generating higher revenues. This expectation, coupled with cost reductions that have taken place across the corporation, are expected to result in rising earnings per share for the nonelectric businesses as a whole.

Our outlook for 2012 is dependent on a variety of factors and is subject to the risks and uncertainties discussed in Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

Our significant accounting policies are described in note 1 to our consolidated financial statements. The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource and transmission rider revenues, valuations of forward energy contracts, percentage-of-completion, warranty and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. The following critical accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements.

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses for our electric utility and corporate employees are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. Further discussion of our pension and postretirement benefit plans and related assumptions is included in note 12 to our consolidated financial statements.

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

The pension benefit cost for 2012 for our noncontributory funded pension plan is expected to be $8.5 million compared to $6.0 million in 2011, reflecting no change in the assumed rate of return on pension plan assets of 8.0% in 2011 and 2012, but reflecting a decrease in the estimated discount rate used to determine annual benefit cost accruals from 6.00% in 2011 to 5.15% in 2012. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of "Aa" published by recognized rating agencies, along with bond matching models specific to our plans as a basis to determine the rate.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2011, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2011 pension benefit cost by $514,000; a 0.25 decrease in the discount rate would have increased our 2011 pension benefit cost by

$667,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2011 pension benefit cost by $612,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2011 pension benefit cost by $518,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2011 pension benefit cost by $442,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase in the discount rate would have decreased our 2011 postretirement medical benefit costs by $26,000. A 0.25 decrease in the discount rate would have increased our 2011 postretirement medical benefit costs by $27,000. See note 12 to our consolidated financial statements for the cost impact of a change in medical cost inflation rates.

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

REVENUE RECOGNITION

DMI, ShoreMaster and our construction companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours at DMI, and costs incurred to total estimated costs on all other construction projects. The duration of the majority of these contracts is less than a year. Revenues recognized on jobs in progress as of December 31, 2011 were $608 million. Any expected losses on jobs in progress at year-end 2011 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

OTP's forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under generally accepted accounting principles. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models and, as such, are estimates. The forward energy sales contracts that are marked to market as of December 31, 2011, are 100% offset by forward energy purchase contracts in terms of volumes and delivery periods but not in terms of delivery points. The differential in forward prices at the different delivery locations currently results in a net mark-to-market unrealized gain on OTP's open forward contracts. OTP's recognized but unrealized net gains of $894,000 on forward purchases and sales of electricity marked to market on December 31, 2011 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	1st Qtr 2012	2nd Qtr 2012	3rd Qtr 2012	4th Qtr 2012	Total
Net Gain	$ 511	$ 222	$ 81	$ 80	$ 894

ALLOWANCE FOR DOUBTFUL ACCOUNTS

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

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

During 2011, $1,072,000 of bad debt expense (0.1% of total 2011 revenue of $1.1 billion) was recorded and the allowance for doubtful accounts was $3.4 million (2.9% of gross trade accounts receivable) as of December 31, 2011.

General economic conditions and specific geographic concerns are major factors that may affect the adequacy of the allowance and may result in a change in the annual bad debt expense. An increase or decrease in our consolidated allowance for doubtful accounts based on one percentage point of outstanding trade receivables at December 31, 2011 would result in a $1.2 million increase or decrease in bad debt expense.

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

DEPRECIATION EXPENSE AND DEPRECIABLE LIVES
The provisions for depreciation of electric utility property for financial reporting purposes are made on the straight-line method based on the estimated service lives (5 to 70 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.94% in 2011, 3.01% in 2010 and 2.90% in 2009. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

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

TAXATION
We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2011 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of Accounting Standards Codification (ASC) 740, Income Taxes, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

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

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

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

In 2011, asset impairments were recorded at DMI and OTESCO. See note 1 to our consolidated financial statements for details. As of December 31, 2011 an assessment of the carrying amounts of our remaining long-lived assets and other intangibles indicated these assets were not impaired.

GOODWILL IMPAIRMENT

Goodwill is required to be evaluated annually for impairment, according to ASC 350-20-35, Goodwill - Subsequent Measurement. The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. Step one is to test for potential impairment and requires that the fair value of the reporting unit be compared to its book value including goodwill. If the fair value is higher than the book value, no impairment is recognized. If the fair value is lower than the book value, a second step must be performed. The second step is to measure the amount of impairment loss, if any, and requires that a hypothetical purchase price allocation be done to determine the implied fair value of goodwill. This fair value is then compared to the carrying amount of goodwill. If the implied fair value is lower than the carrying amount, an impairment adjustment must be recorded.

We believe accounting estimates related to goodwill impairment are critical because the underlying assumptions used for the discounted cash flow can change from period to period and could potentially cause a material impact to the income statement. Management's assumptions about inflation rates and other internal and external economic conditions, such as earnings growth rate, require significant judgment based on fluctuating rates and expected revenues. Additionally, ASC 350-20-35 requires goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

We currently have $19.3 million of goodwill recorded on our consolidated balance sheet related to the acquisitions of the companies in our Plastics segment. Our Plastics segment consists of businesses producing polyvinyl chloride (PVC) pipe in the upper Midwest and Southwest regions of the United States. Our Plastics segment has continued to generate cash flows and earnings during the 2008 through 2011 timeframe while being in an industry that has been significantly challenged due to low housing and construction starts. If the current economic conditions were to more severely impact the sales and profitability of this segment such that it started to generated lower levels of operating profits and ultimately turn to net losses, these reductions in anticipated cash flows from the business may indicate, in a future period, that its fair value is less than the carrying value resulting in an impairment of some or all of the goodwill associated with the Plastics segment along with a corresponding charge against earnings.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. An assessment of the carrying amounts of our goodwill as of December 31, 2011 indicated the fair values of our reporting units are substantially in excess of their respective book values and not impaired.

ACQUISITION METHOD OF ACCOUNTING

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

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

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

FORWARD-LOOKING INFORMATION - SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the Act). When used in this Form 10-K and in future filings by the Company with the Securities and Exchange Commission (SEC), in the Company's press releases and in oral statements, words such as "may," "will," "expect," "anticipate," "continue," "estimate," "project," "believes" or similar expressions are intended to identify forward-looking statements within the meaning of the Act. Such statements are based on current expectations and assumptions, and entail various risks and uncertainties that could cause actual results to differ materially from those expressed in such forward-looking statements. Such risks and uncertainties include the various factors set forth in Item 1A. Risk Factors of this Annual Report on Form 10-K and in our other SEC filings.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2011 we had no exposure to market risk associated with interest rates because we had no debt outstanding subject to variable interest rates. At December 31, 2011 we had exposure to changes in foreign currency exchange rates. DMI has market risk related to changes in foreign currency exchange rates at its plant in Fort Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

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

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

DMI and the companies in our Manufacturing segment are exposed to market risk related to changes in commodity prices for steel, lumber, aluminum, cement and resin. The price and availability of these raw materials could affect the revenues and earnings of our Wind Energy and Manufacturing segments.

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

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2011 OTP had recognized, on a pretax basis, $894,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP’s forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP’s power services’ personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy sales contracts that are marked to market as of December 31, 2011, are 100% offset by forward energy purchase contracts in terms of volumes, delivery periods but not in terms of delivery points. The differential in forward prices at the different delivery locations currently results in a mark-to-market unrealized gain on OTP’s open forward contracts.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with our energy trading activities. Additionally, we have a Value at Risk (VaR) limit to further manage market price risk. There was price risk on open positions as of December 31, 2011 because the open purchases were not at the same delivery points as the open sales.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of December 31, 2011 and December 31, 2010, and the change in the Company's consolidated balance sheet position from December 31, 2010 to December 31, 2011 and December 31, 2009 to December 31, 2010:

(in thousands)	December 31, 2011	December 31, 2010
Current Asset – Marked-to-Market Gain	$ 3,803	$ 6,875
Regulatory Asset – Current Deferred Marked-to-Market Loss	5,208	4,370
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	10,749	7,684
Total Assets	19,760	18,929
Current Liability – Marked-to-Market Loss	(18,770)	(17,991)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(96)	(117)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	--	(58)
Total Liabilities	(18,866)	(18,166)
Net Fair Value of Marked-to-Market Energy Contracts	$ 894	$ 763

(in thousands)	Year ended December 31, 2011	Year ended December 31, 2010
Fair Value at Beginning of Year	$ 763	$ 1,030
Less: Amounts Realized on Contracts Entered into in 2009	(306)	(389)
Amounts Realized on Contracts Entered into in 2010	(50)	--
Changes in Fair Value of Contracts Entered into in 2009	(14)	--
Changes in Fair Value of Contracts Entered into in 2010	(72)	--
Net Fair Value of Contracts Entered into in Prior Year at Year End	321	641
Changes in Fair Value of Contracts Entered into in Current Year	573	122
Net Fair Value at End of Year	$ 894	$ 763

The $894,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2011 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	1st Qtr 2012	2nd Qtr 2012	3rd Qtr 2012	4th Qtr 2012	Total
Net Gain	$ 511	$ 222	$ 81	$ 80	$ 894

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

	Year Ended December 31,		
(in thousands)	2011	2010	2009
Net Gains on Forward Electric Energy Contracts	$ 926	$ 2,135	$ 2,184

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of

December 31, 2011 was $737,000. As of December 31, 2011 OTP had a net credit risk exposure of $1,677,000 from ten counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2011 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The $1,677,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2011. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders of
Otter Tail Corporation

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and its subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, common shareholders' equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2011. We also have audited the Company's internal control over financial reporting as of December 31, 2011 based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 29, 2012

OTTER TAIL CORPORATION
Consolidated Balance Sheets, December 31

(in thousands)		2011		2010
ASSETS				
Current Assets				
Cash and Cash Equivalents	$	14,652	$	--
Accounts Receivable:				
Trade (less allowance for doubtful accounts of $3,435 for 2011 and $6,188 for 2010)		116,522		94,971
Other		18,807		18,283
Inventories		77,983		72,009
Deferred Income Taxes		12,307		10,028
Accrued Utility Revenues		13,719		13,936
Costs and Estimated Earnings in Excess of Billings		67,109		67,352
Regulatory Assets		27,391		21,485
Other		21,414		18,330
Assets of Discontinued Operations		29,692		197,269
Total Current Assets		399,596		513,663
Investments		11,093		9,708
Other Assets		26,997		27,356
Goodwill		39,406		39,406
Other Intangibles--Net		15,286		16,241
Deferred Debits				
Unamortized Debt Expense		6,458		6,444
Regulatory Assets		124,137		108,668
Total Deferred Debits		130,595		115,112
Plant				
Electric Plant in Service		1,372,534		1,332,974
Nonelectric Operations		310,320		288,479
Construction Work in Progress		54,439		41,976
Total Gross Plant		1,737,293		1,663,429
Less Accumulated Depreciation and Amortization		659,744		614,360
Net Plant		1,077,549		1,049,069
Total Assets	$	1,700,522	$	1,770,555

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Balance Sheets, December 31

(in thousands, except share data)	2011	2010
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$ --	$ 79,490
Current Maturities of Long-Term Debt	3,033	224
Accounts Payable	115,514	102,537
Accrued Salaries and Wages	19,043	17,675
Accrued Taxes	11,841	11,749
Derivative Liabilities	18,770	17,991
Other Accrued Liabilities	5,540	5,609
Liabilities of Discontinued Operations	13,763	49,705
Total Current Liabilities	187,504	284,980
Pensions Benefit Liability	106,818	73,538
Other Postretirement Benefits Liability	48,263	42,372
Other Noncurrent Liabilities	19,002	21,004
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	177,264	155,436
Deferred Tax Credits	33,182	44,945
Regulatory Liabilities	69,106	66,209
Other	520	507
Total Deferred Credits	280,072	267,097
Capitalization (page 73)		
Long-Term Debt, Net of Current Maturities	471,915	433,676
Class B Stock Options of Subsidiary	--	525
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2011 and 2010 – 155,000 Shares	15,500	15,500
Cumulative Preference Shares – Authorized 1,000,000 Shares Without Par Value; Outstanding - None	--	--
Common Shares, Par Value $5 Per Share--Authorized, 50,000,000 Shares; Outstanding, 2011--36,101,695 Shares; 2010—36,002,739 Shares	180,509	180,014
Premium on Common Shares	253,123	251,919
Retained Earnings	141,248	198,443

Accumulated Other Comprehensive (Loss) Income		(3,432)		1,487
Total Common Equity		571,448		631,863
Total Capitalization		1,058,863		1,081,564
Total Liabilities and Equity	$	1,700,522	$	1,770,555

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Statements of Income--For the Years Ended December 31

(in thousands, except per-share amounts)	2011	2010	2009
Operating Revenues			
Electric	$ 342,505	$ 344,146	$ 314,472
Nonelectric	735,345	548,045	504,220
Total Operating Revenues	1,077,850	892,191	818,692
Operating Expenses			
Production Fuel - Electric	69,017	73,102	59,387
Purchased Power - Electric System Use	43,451	44,788	52,942
Electric Operation and Maintenance Expenses	115,863	112,174	106,457
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	646,696	470,844	417,443
Other Nonelectric Expenses	66,731	69,195	65,775
Asset Impairment Charge	3,613	19,251	--
Depreciation and Amortization	70,000	69,399	64,724
Property Taxes - Electric	10,190	9,364	8,853
Total Operating Expenses	1,025,561	868,117	775,581
Operating Income	52,289	24,074	43,111
Other Income	2,736	1,057	4,651
Interest Charges	35,818	36,940	28,417
Income (Loss) Before Income Taxes – Continuing Operations	19,207	(11,809)	19,345
Income Tax Expense (Benefit) – Continuing Operations	2,087	(983)	(5,294)
Net Income (Loss) from Continuing Operations	17,120	(10,826)	24,639
Discontinued Operations			
Income - net of Income Tax Expense of $223, $5,130, and $689 for the respective periods	354	9,775	1,392
Impairment Loss - net of Income Tax (Benefit) of ($17,444), ($196) and ($0) for the respective periods	(39,391)	(293)	--
Gain on Disposition - net of Income Tax Expense of $5,851 in 2011	8,674	--	--
Net (Loss) Income from Discontinued Operations	(30,363)	9,482	1,392
Total Net (Loss) Income	(13,243)	(1,344)	26,031
Preferred Dividend Requirement and Other Adjustments	1,058	833	736
Earnings (Loss) Available for Common Shares	$ (14,301)	$ (2,177)	$ 25,295
Average Number of Common Shares Outstanding--Basic	35,922	35,784	35,463
Average Number of Common Shares Outstanding--Diluted	36,082	35,784	35,717

Basic Earnings (Loss) Per Common Share:			
Continuing Operations (net of preferred dividend requirement)	$ 0.46	$ (0.32)	$ 0.67
Discontinued Operations (net of other adjustments)	$ (0.86)	$ 0.26	$ 0.04
	$ (0.40)	$ (0.06)	$ 0.71
Diluted Earnings (Loss) Per Common Share:			
Continuing Operations (net of preferred dividend requirement)	$ 0.45	$ (0.32)	$ 0.67
Discontinued Operations (net of other adjustments)	$ (0.85)	$ 0.26	$ 0.04
	$ (0.40)	$ (0.06)	$ 0.71
Dividends Declared Per Common Share	$ 1.19	$ 1.19	$ 1.19

See accompanying notes to consolidated financial statements.

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

(in thousands)	2011	2010	2009
Net (Loss) Income	$ (13,243)	$ (1,344)	$ 26,031
Other Comprehensive Income (Loss):			
Unrealized (Loss) Gain on Available-for-Sale Securities:			
Net (Loss) Gain Arising During Period	(121)	50	123
Income Tax Benefit (Expense)	48	(20)	(49)
Net (Loss) Gain on Available-for-Sale Securities – net-of-tax	(73)	30	74
Foreign Currency Translation Adjustment Gain (Loss):			
Unrealized Net Change During Period	303	1,335	3,275
Reversal of Previously Recognized Gains Realized on Sale of IPH in 2011	(6,068)		
Income Tax Benefit (Expense)	1,787	(15)	(1,310)
Foreign Currency Translation Adjustment (Loss) Gain – net-of-tax	(3,978)	1,320	1,965
Pension and Postretirement Benefit Plans:			
Actuarial (Losses) Gains Net of Regulatory Allocation Adjustment	(1,686)	1,738	(1,185)
Amortization of Unrecognized Postretirement Benefit Costs	239	682	595
Income Tax Benefit (Expense)	579	(968)	236
Pension and Postretirement Benefit Plans – net-of-tax	(868)	1,452	(354)
Total Other Comprehensive (Loss) Income	(4,919)	2,802	1,685
Total Comprehensive (Loss) Income	$ (18,162)	$ 1,458	$ 27,716

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Statements of Common Shareholders' Equity

(in thousands, except common shares outstanding)	Common Shares Outstanding	Par Value, Common Share	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
Balance, December 31, 2008	35,384,620	$ 176,923	$ 241,731	$ 260,364	$ (3,000)	$ 676,018
Common Stock Issuances, Net of Expenses	437,843	2,189	6,243			8,432
Common Stock Retirements	(10,183)	(51)	(178)			(229)
Net Income				26,031		26,031
Other Comprehensive Income					1,685	1,685
Tax Benefit for Exercise of Stock Options			(23)			(23)
Stock Incentive Plan Performance Award Accrual			2,592			2,592
Vesting of Restricted Stock Granted to Employees			52			52
Premium on Purchase of Stock for Employee Purchase Plan			(19)			(19)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(42,307)		(42,307)
Balance, December 31, 2009	35,812,280	$ 179,061	$ 250,398	$ 243,352	$ (1,315) (a)	$ 671,496
Common Stock Issuances, Net of Expenses	208,333	1,042	2,054			3,096
Common Stock Retirements	(17,874)	(89)	(312)			(401)
Net Loss				(1,344)		(1,344)
Other Comprehensive Income					2,802	2,802
Tax Benefit – Stock Compensation			(1,404)			(1,404)
Stock Incentive Plan Performance Award Accrual			1,415			1,415
Premium on Purchase of Stock for Employee Purchase Plan			(232)			(232)

Premium on Purchase of Subsidiary Class B Stock and Options				(98)		(98)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(42,731)		(42,731)
Balance, December 31, 2010	36,002,739	$ 180,014	$ 251,919	$ 198,443	$ 1,487 (a)	$ 631,863
Common Stock Issuances, Net of Expenses	154,225	771	2,671			3,442
Common Stock Retirements	(55,269)	(276)	(906)			(1,182)
Net Loss				(13,243)		(13,243)
Other Comprehensive Loss					(4,919)	(4,919)
Tax Benefit – Stock Compensation			(875)			(875)
Employee Stock Incentive Plan Expense			606			606
Premium on Purchase of Stock for Employee Purchase Plan			(292)			(292)
Premium on Purchase of Subsidiary Class B Stock and Options				(322)		(322)
Cumulative Preferred Dividends				(735)		(735)
Common Dividends				(42,895)		(42,895)
Balance, December 31, 2011	36,101,695	$ 180,509	$ 253,123	$ 141,248	$ (3,432) (a)	$ 571,448

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

(in thousands)	2011	2010	2009
Unrealized Gain on Marketable Equity Securities:			
Before Tax	$ 23	$ 145	$ 94
Tax Effect	(9)	(58)	(38)
Unrealized Gain on Marketable Equity Securities – Net-of-Tax	14	87	56
Foreign Currency Exchange Translation – Net-of-Tax:			
Before Tax	--	5,765	4,430
Tax Effect	--	(1,787)	(1,772)
Foreign Currency Exchange Translation – Net-of-Tax	--	3,978	2,658
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits:			
Before Tax	(5,743)	(4,296)	(6,715)
Tax Effect	2,297	1,718	2,686
	(3,446)	(2,578)	(4,029)

Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits – Net-of-Tax			
Accumulated Other Comprehensive (Loss) Income:			
Before Tax	(5,720)	1,614	(2,191)
Tax Effect	2,288	(127)	876
Net Accumulated Other Comprehensive (Loss) Income	$ (3,432)	$ 1,487	$ (1,315)

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION

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

(in thousands)	2011	2010	2009
Cash Flows from Operating Activities			
Net (Loss) Income	$ (13,243)	$ (1,344)	$ 26,031
Adjustments to Reconcile Net (Loss) Income to Net Cash Provided by Operating Activities:			
Net Gain from Sale of Discontinued Operations	(8,674)	--	--
Net Loss (Income) from Discontinued Operations	39,037	(9,482)	(1,392)
Depreciation and Amortization	70,000	69,399	64,724
Asset Impairment Charge	3,613	19,251	--
Deferred Tax Valuation Adjustments and Tax Rate Reduction	--	8,300	--
Deferred Tax Credits	(2,386)	(2,715)	(2,331)
Deferred Income Taxes	13,292	8,770	43,179
Change in Deferred Debits and Other Assets	(25,054)	30	(18,574)
Discretionary Contribution to Pension Fund	--	(20,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	35,167	3,686	24,758
Allowance for Equity (Other) Funds Used During Construction	(861)	(4)	(3,180)
Change in Derivatives Net of Regulatory Deferral	72	208	(1,153)
Stock Compensation Expense – Equity Awards	2,177	2,923	3,563
Other—Net	1,258	1,836	2,142
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	(22,398)	(33,603)	39,605
Change in Inventories	(5,974)	(7,386)	19,042
Change in Other Current Assets	3,565	(9,927)	12,901
Change in Payables and Other Current Liabilities	(657)	23,138	(30,514)
Change in Interest Payable and Income Taxes Receivable/Payable	(9,238)	40,971	(20,177)
Net Cash Provided by Continuing Operations	79,696	94,051	154,624
Net Cash Provided by Discontinued Operations	24,687	10,966	8,126
Net Cash Provided by Operating Activities	104,383	105,017	162,750
Cash Flows from Investing Activities			
Capital Expenditures	(73,677)	(61,549)	(171,761)
2009 American Recovery and Reinvestment Act Grant - Luverne Wind Farm	--	--	30,182
Proceeds from Disposal of Noncurrent Assets	2,625	1,049	1,192
Net Increase in Other Investments	(40)	(2,855)	(5,733)
Net Cash Used in Investing Activities - Continuing Operations	(71,092)	(63,355)	(146,120)
Net Proceeds from Sale of Discontinued Operations	107,310	--	--
Net Cash Used in Investing Activities - Discontinued Operations	(30,795)	(21,812)	(1,620)
Net Cash Provided by (Used in) Investing Activities	5,423	(85,167)	(147,740)

Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	(8,463)	8,470	--
Net Short-Term (Repayments) Borrowings	(79,490)	71,905	(127,329)
Proceeds from Issuance of Common Stock	--	549	7,420
Proceeds from Issuance of Class B Stock of Subsidiary	--	153	--
Common Stock Issuance Expenses	--	(142)	(23)
Payments for Retirement of Common Stock	(1,182)	(401)	(229)
Payments for Retirement of Class B Stock and Options of Subsidiary	--	(1,012)	--
Proceeds from Issuance of Long-Term Debt	142,006	--	174,994
Short-Term and Long-Term Debt Issuance Expenses	(1,666)	(1,699)	(5,526)
Payments for Retirement of Long-Term Debt	(100,958)	(58,945)	(23,047)
Dividends Paid and Other Distributions	(43,923)	(43,698)	(43,043)
Net Cash Used in Financing Activities - Continuing Operations	(93,676)	(24,820)	(16,783)
Net Cash (Used in) Provided by Financing Activities - Discontinued Operations	(1,827)	1,104	(303)
Net Cash Used in Financing Activities	(95,503)	(23,716)	(17,086)
Less: Net Change in Cash and Cash Equivalents - Discontinued Operations	673	(1,300)	2,036
Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations	(324)	(566)	(1,057)
Net Change in Cash and Cash Equivalents	14,652	(5,732)	(1,097)
Cash and Cash Equivalents at Beginning of Period	--	5,732	6,829
Cash and Cash Equivalents at End of Period	$ 14,652	$ --	$ 5,732

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION
Consolidated Statements of Capitalization, December 31

(in thousands, except share data)		2011		2010
Short-Term Debt				
Otter Tail Corporation Credit Agreement	$	--	$	54,176
OTP Credit Agreement		--		25,314
Total Short-Term Debt	$	--	$	79,490
Long-Term Debt				
Obligations of Otter Tail Corporation				
9.000% Notes, due December 15, 2016	$	100,000	$	100,000
Senior Unsecured Note 8.89%, due November 30, 2017		50,000		50,000
North Dakota Development Note, 3.95%, due April 1, 2018		458		--
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021		1,431		--
Total – Otter Tail Corporation		151,889		150,000
Obligations of Otter Tail Power Company				
Senior Unsecured Notes 6.63%, Retired December 1, 2011		--		90,000
Pollution Control Refunding Revenue Bonds, due December 1, 2012, (early retired December 1, 2011)		--		10,400
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017		33,000		33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017		5,090		5,100
Senior Unsecured Notes 4.63%, due December 1, 2021		140,000		--
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022		30,000		30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022		20,105		20,215
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027		42,000		42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037		50,000		50,000
Total – Otter Tail Power Company		320,195		280,715
Obligations of Varistar Corporation				
Capital Lease, variable 3.54% at December 31, 2011, due April 20, 2012		2,868		3,021
Other – Various up to 13.31% at December 31, 2010		--		169
Total – Varistar Corporation		2,868		3,190
Total		474,952		433,905
Less:				
Current Maturities – Otter Tail Corporation		165		--
Current Maturities – Varistar Corporation		2,868		224
Unamortized Debt Discount – Otter Tail Corporation		4		5
Total Long-Term Debt		471,915		433,676
Class B Stock Options of Subsidiary		--		525

Cumulative Preferred Shares—Without Par Value (Stated and Liquidating Value $100 a Share)— Authorized 1,500,000 Shares; nonvoting and redeemable at the option of the Company:					
Series Outstanding:	Call Price December 31, 2011				
$3.60, 60,000 Shares	$102.2500		6,000		6,000
$4.40, 25,000 Shares	$102.0000		2,500		2,500
$4.65, 30,000 Shares	$101.5000		3,000		3,000
$6.75, 40,000 Shares	$100.6750		4,000		4,000
Total Preferred			15,500		15,500
Cumulative Preference Shares--Without Par Value, Authorized 1,000,000 Shares; Outstanding: None					
Total Common Shareholders' Equity			571,448		631,863
Total Capitalization		$	1,058,863	$	1,081,564

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Notes to Consolidated Financial Statements
For the years ended December 31, 2011, 2010 and 2009

1. Summary of Significant Accounting Policies

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

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

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

Plant, Retirements and Depreciation
Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $628,000 in 2011, $76,000 in 2010 and $1,036,000 in 2009. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.94% in 2011, 3.01% in 2010 and 2.90% in 2009. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting, and are depreciated on a straight-line basis over the assets’ estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. The amount of interest capitalized on nonelectric plant was $0 in 2011, $0 in 2010 and $200,000 in 2009. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

Jointly Owned Plants
The consolidated balance sheets include OTP's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the December 31, 2011 and 2010 consolidated balance sheets:

(in thousands)	2011	2010
Big Stone Plant:		
Electric Plant in Service	$ 143,993	$ 135,982
Construction Work in Progress	2,674	3,163
Accumulated Depreciation	(87,669)	(81,264)
Net Plant	$ 58,998	$ 57,881
Coyote Station:		
Electric Plant in Service	$ 156,213	$ 155,813
Construction Work in Progress	1,533	178
Accumulated Depreciation	(97,090)	(90,005)
Net Plant	$ 60,656	$ 65,986

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

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

In the fourth quarter of 2011, DMI Industries, Inc. (DMI) recorded a $3.1 million asset impairment charge on its plant in Fort Erie, Ontario. DMI temporarily idled this plant in the fourth quarter, as the plant had completed all of its current tower orders. After the Ontario provincial election in October 2011, DMI received, and is working on, numerous requests for quotes for towers and capacity in the 2012 - 2013 timeframe given the certainty the election brought to the Green Energy Act staying in place in Canada. DMI currently does not have orders booked for its Fort Erie facility for 2012 and does not intend to reopen the plant until orders are received of such a magnitude as to justify a start up. DMI is not expecting to be able to recover the current book value of its Fort Erie plant and equipment and, accordingly, recorded the $3.1 million asset impairment charge based on independent appraisals of the current market value of the facility. Also in the fourth quarter of 2011, Otter Tail Energy Services Company (OTESCO) recorded a $0.5 million asset impairment charge related to its wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota based on market indicators of the value of these assets held for sale.

Income Taxes
Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes investment tax credits over the estimated lives of related property. The Company records income taxes in accordance with ASC 740, Income Taxes, and has recognized in its consolidated financial statements the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. The term "more-likely-than-not" means a likelihood of more than 50%. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 15 to the consolidated financial statements regarding the Company’s accounting for uncertain tax positions.

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

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

current trends. In the case of derivative instruments, such as OTP’s forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with ASC 815, Derivatives and Hedging. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

For the Company’s operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

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

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered.

OTP's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on the Company's consolidated statement of income. Under ASC 815, OTP's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. See note 5 for further discussion.

Wind Energy operating revenues are recorded on a percentage-of-completion method for production of wind towers, similar to construction-type contracts.

Manufacturing operating revenues are recorded when products are shipped and on a percentage-of-completion basis for construction type contracts.

Construction operating revenues are recorded on a percentage-of-completion basis.

Plastics operating revenues are recorded when the product is shipped.

Some of the operating businesses in the Company's Wind Energy, Manufacturing and Construction segments enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours at the Company's wind tower manufacturer and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. Following are the percentages of the Company's consolidated revenues recorded under the percentage-of-completion method:

	2011	2010	2009
Percentage-of-Completion Revenues	37.2 %	32.5 %	35.2 %

The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2011	December 31, 2010
Costs Incurred on Uncompleted Contracts	$ 583,346	$ 460,125
Less Billings to Date	(550,070)	(430,471)
Plus Estimated Earnings Recognized	24,478	31,231
	$ 57,754	$ 60,885

The following costs and estimated earnings in excess of billings are included in the Company's consolidated balance sheets. Billings in excess of costs and estimated earnings on uncompleted contracts are included in Accounts Payable.

(in thousands)	December 31, 2011	December 31, 2010
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 67,109	$ 67,352
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(9,355)	(6,467)
	$ 57,754	$ 60,885

Included in Costs and Estimated Earnings in Excess of Billings are the following amounts at DMI, the Company's wind tower manufacturer:

(in thousands)	December 31, 2011	December 31, 2010
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts - DMI	$54,541	$58,990

These amounts are related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

Warranty Reserves

The Company establishes reserves for estimated product warranty costs at the time revenue is recognized based on historical warranty experience and additionally for any known product warranty issues. Certain Company products carry one to fifteen year warranties. Although the Company engages in extensive product quality programs and processes, the Company's warranty obligations have been and may in the future be affected by product failure rates, repair or field replacement costs and additional development costs incurred in correcting product failures.

(in thousands)		
Warranty Reserve Balance, December 31, 2010	$	2,676
Provision for Warranties Used During the Year		1,644
Less Settlements Made During the Year		1,215
Increase in Warranty Estimates for Prior Years		65
Warranty Reserve Balance, December 31, 2011	$	3,170

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 the Company is required to cover remediation expenses in addition to regular warranty coverage, the Company could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect the Company's consolidated results of operations and financial condition.

Retainage

Accounts Receivable include the following amounts, billed under contracts by the Company's subsidiaries, that have been retained by customers pending project completion:

(in thousands)	December 31, 2011	December 31, 2010
Accounts Receivable Retained by Customers	$13,526	$11,848

Sales of Receivables

DMI is a party to a $40 million receivables sales agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement is subject to renewal in July 2012. The Company is currently reviewing its options regarding this agreement. The current discount rate is 3-month LIBOR plus 4%. In compliance with guidance under ASC 860-20, Sales of Financial Assets, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows. Following are the amounts of accounts receivable sold and discounts, fees and commissions paid under DMI's receivables sales agreement with General Electric Capital Corporation:

(in thousands)	2011	2010	2009
Accounts Receivable Sold	$71,977	$62,651	$133,900
Discounts, Fees and Commissions Paid on Sale of Accounts Receivable	635	208	430

Shipping and Handling Costs

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

Foreign Currency Translation
The functional currency for the Canadian subsidiary of DMI is the U.S. dollar (USD). There are no foreign currency translation gains or losses related to this entity. However, this subsidiary may realize foreign currency transaction gains or losses on settlement of liabilities related to goods or services purchased in Canadian dollars (CAD). Foreign currency transaction losses related to balance sheet adjustments of CAD liabilities to USD equivalents and realized losses on settlement of those liabilities were $21,000 USD in 2011 and $740,000 USD in 2010 as a result of increases in the value of the Canadian dollar relative to the U.S. dollar in 2011 and 2010. Foreign currency transaction gains related to balance sheet adjustments of CAD liabilities to USD equivalents and realized gains on settlement of those liabilities were $77,000 USD in 2009 as a result of decreases in the value of the Canadian dollar relative to the U.S. dollar in 2009.

Use of Estimates
The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource and transmission rider revenues, accrued conservation improvement program incentives and bonuses, valuations of forward energy contracts, percentage-of-completion, warranty reserves and actuarially determined benefits costs and liabilities. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

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

Investments
The following table provides a breakdown of the Company’s investments at December 31, 2011 and 2010:

(in thousands)		December 31, 2011		December 31, 2010
Cost Method:				
Portion of IPH Sales Proceeds Held in Escrow Account1	$	3,001	$	--
Economic Development Loan Pools		320		387
Other		206		244
Equity Method:				
Affordable Housing and Other Partnerships		276		610
Marketable Securities Classified as Available-for-Sale		8,790		8,467
Total Investments	$	12,593	$	9,708
Less: IPH Escrow Funds Reported under Other Current Assets1		(1,500)		--
Investments	$	11,093	$	9,708

1$I.5 million accessible within one year is classified and reported under other current assets.

The Company’s marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their market values on December 31, 2011. See further discussion below and under note 13.

Fair Value Measurements

The Company follows ASC 820, Fair Value Measurements and Disclosures, for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following table presents, for each of these hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31:

2011 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds	$ 364	$ --	
Forward Gasoline Purchase Contracts	9		
Forward Energy Contracts		3,803	
Regulatory Asset – Deferred Mark-to-Market Losses on Forward Energy Contracts		15,957	
Investments of Captive Insurance Company:			
Corporate Debt Securities		8,083	
U.S. Government Debt Securities	707		
Proceeds from Sale of Idaho Pacific Holdings, Inc. (IPH) Held In Escrow Account	3,001		
Total Assets	$ 4,081	$ 27,843	
Liabilities:			
Forward Energy Contracts	$ --	$ 18,770	
Regulatory Liability – Deferred Mark-to-Market Gains on Forward Energy Contracts		96	
Total Liabilities	$ --	$ 18,866	

2010 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$ 800	$ --	
Forward Gasoline Purchase Contracts	58		
Forward Energy Contracts		6,875	
Regulatory Asset – Deferred Mark-to-Market Losses on Forward Energy Contracts		12,054	
Investments of Captive Insurance Company:			
Corporate Debt Securities	8,467		
Total Assets	$ 9,325	$ 18,929	
Liabilities:			
Forward Energy Contracts	$ --	$ 17,991	
Regulatory Liability – Deferred Mark-to-Market Gains on Forward Energy Contracts		175	
Total Liabilities	$ --	$ 18,166	

The valuation methods and inputs used to develop the level 2 fair value measurements for forward energy contracts are described in note 5 to consolidated financial statements.

Inventories

The Electric segment inventories are reported at average cost. All other segments' inventories are stated at the lower of cost (first-in, first-out) or market. Inventories consist of the following:

(in thousands)	December 31, 2011	December 31, 2010
Finished Goods	$ 21,373	$ 24,429
Work in Process	11,951	7,171
Raw Material, Fuel and Supplies	44,659	40,409
Total Inventories	$ 77,983	$ 72,009

Goodwill and Other Intangible Assets

The Company accounts for goodwill and other intangible assets in accordance with the requirements of ASC 350, Intangibles—Goodwill and Other, measuring its goodwill and indefinite-lived intangible assets for impairment annually in the fourth quarter, and more often when events indicate the assets may be impaired. Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC 360-10-35, Property, Plant, and Equipment—Overall—Subsequent Measurement.

During the first six months of 2010, ShoreMaster Inc.'s (ShoreMaster) performance was below its 2010 budget and below its performance over the same period in 2009. While updating the second quarter earnings forecast, it became apparent that ShoreMaster's commercial marina and waterfront lines of business continued to be adversely impacted by the economic recession in 2010. The Consumer Confidence Index declined 9.8% in June 2010 around increasing uncertainty and apprehension about the future state of the economy and labor market. The Purchasing Managers' Index also experienced a drop in June around concerns over the status of the economic recovery. These conditions resulted in a reduction in incoming orders in the commercial marina business. As a result of the poor first half 2010 performance and the economic indicators, ShoreMaster projected a slower recovery from the economic recession than was expected in 2009.

In light of the continuing economic uncertainty and delayed economic recovery, ShoreMaster revised its sales and operating cash flow projections downward in the second quarter of 2010 and reassessed its fair value to determine if its goodwill and other assets were impaired. ShoreMaster used a discounted cash flow model using a risk adjusted weighted average cost of capital discount rate of 14% to determine its fair value. The fair value determination indicated ShoreMaster's goodwill and intangible assets were 100% impaired and its long-lived assets were partially impaired, resulting in the following impairment charges in June 2010:

(in thousands)		
Goodwill	$	12,259
Brand/Trade Name		4,786
Other Intangible Assets		140
Long-Lived Assets		2,066
Total Asset Impairment Charges	$	19,251

The following table summarizes changes to goodwill by business segment during 2011:

(in thousands)	Gross Balance December 31, 2010	Accumulated Impairments	Balance (net of impairments) December 31, 2010	Adjustments to Goodwill in 2011	Balance (net of impairments) December 31, 2011
Electric	$ 240	$ (240)	$ --	$ --	$ --
Wind Energy	288	--	288	--	288
Manufacturing	24,445	(12,259)	12,186	--	12,186
Construction	7,630	--	7,630	--	7,630
Plastics	19,302	--	19,302	--	19,302
Total	$ 51,905	$ (12,499)	$ 39,406	$ --	$ 39,406

Other Intangible Assets

The following table summarizes the components of the Company's intangible assets at December 31:

2011 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Customer Relationships	$ 16,811	$ 3,236	$ 13,575	15 – 25 years
Covenants Not to Compete	713	709	4	3 – 5 years
Other Intangible Assets Including Contracts	2,192	485	1,707	5 – 30 years
Total	$ 19,716	$ 4,430	$ 15,286	

2010 (in thousands)							
Amortized Intangible Assets:							
Customer Relationships	$	16,811	$	2,388	$	14,423	15 – 25 years
Covenants Not to Compete		713		685		28	3 – 5 years
Other Intangible Assets Including Contracts		2,192		402		1,790	5 – 30 years
Total	$	19,716	$	3,475	$	16,241	

The amortization expense for these intangible assets was:

(in thousands)	2011	2010	2009
Amortization Expense – Intangible Assets	$956	$943	$1,056

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

(in thousands)	2012	2013	2014	2015	2016
Estimated Amortization Expense – Intangible Assets	$981	$977	$977	$977	$945

Supplemental Disclosures of Cash Flow Information

(in thousands)	2011	2010	2009
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$ 19,384	$ 830	$ (3,723)
Cash Paid During the Year for:			
Interest (net of amount capitalized)	$ 34,434	$ 33,094	$ 23,563
Income Tax (Refunds) Payments	$ (257)	$ (54,346)	$ (27,412)

Reclassifications and Changes to Presentation

The Company's consolidated balance sheet as of December 31, 2010, and consolidated income statement and consolidated statement of cash flows for the years ended December 31, 2010 and 2009 reflect the reclassifications of the assets and liabilities, operating results and cash flows of IPH, E.W. Wylie Corporation (Wylie), DMS Health Technologies, Inc. (DMS), and Aviva Sports, Inc. (Aviva), a wholly owned subsidiary of ShoreMaster, to discontinued operations as a result of the second quarter 2011 sale of IPH, the December 2011 sale of Wylie, the January 2012 sale of Aviva and February 2012 agreement to sell DMS. The reclassifications had no impact on the Company's total consolidated assets, consolidated net income or cash flows as of and for the years ended December 31, 2010 and 2009.

Certain prior year balance sheet amounts related to regulatory assets and liabilities have been reclassified to conform to the current year presentation, which separately identifies and classifies the current portion of these assets and liabilities. The reclassifications had no impact on the Company's total consolidated assets and liabilities for the year ended December 31, 2010.

In 2011 management reported Minnesota Conservation Improvement Program (MNCIP) incentives in Operating Revenues – Electric rather than Other Income as they had been classified in 2010. The Company has corrected this classification resulting in the following increase in Operating Revenues and Operating Income and decrease in Other Income:

(in thousands)	2010
MNCIP Incentives reclassified from Other Income to Operating Revenue	$ 4,066

The correction had no impact on the Company's net income, total assets, or operating cash flows for the year ended December 31, 2010.

New Accounting Standards

None

2. Business Combinations, Dispositions and Segment Information

The Company acquired no new businesses in 2011, 2010 or 2009 and disposed of no businesses in 2010 or 2009.

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 IPH, its Food Ingredient Processing business, and Wylie, its trucking company, which was included in its Wind Energy segment. On January 18, 2012 the Company sold the assets of Aviva, a wholly owned subsidiary of ShoreMaster that sells a variety of recreational equipment. On February 6, 2012, the Company entered into an agreement to sell DMS, its Health Services business, with an expected closing date of February 29, 2012, subject to certain closing conditions.

The results of operations of IPH, Wylie, Aviva and DMS, are reported as discontinued operations in the Company's consolidated financial statements as of and for the years ended December 31, 2011, 2010 and 2009, and are summarized in note 17 to consolidated financial statements.

Segment Information

The accounting policies of the segments are described under note 1 – Summary of Significant Accounting Policies. As a result of the 2011 and January and February 2012 dispositions, the Company's business structure now includes the following five segments: Electric, Wind Energy, Manufacturing, Construction and Plastics. The chart below indicates the companies included in each segment.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is 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, the electric segment includes OTESCO, which provides technical and engineering services.

Wind Energy consists of DMI, 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 Ontario, Canada. The facility in Ontario, Canada was idled in the fourth quarter of 2011 due to a lack of orders for wind towers.

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.

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 corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

The Company had one customer within the Wind Energy segment that accounted for 10.8% of the Company's consolidated revenues in 2011. No single customer accounted for over 10% of the Company's consolidated revenues in 2010. In 2009, the Company had one customer within the Wind Energy segment that accounted for 17.2% of the Company's consolidated revenues. Substantially all of the Company's long-lived assets are within the United States except for a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

Percent of Sales Revenue by Country for the Year Ended December 31:

	2011		2010		2009	
United States of America	98.2	%	98.5	%	99.0	%
Canada	1.4	%	1.4	%	0.9	%
All Other Countries	0.4	%	0.1	%	0.1	%

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for 2011, 2010 and 2009 is presented in the following table:

(in thousands)	2011	2010	2009
Operating Revenue			
Electric	$342,727	$344,379	$314,666
Wind Energy	201,921	143,603	160,695
Manufacturing	227,116	175,986	161,194
Construction	184,657	134,222	103,831
Plastics	123,669	96,945	80,208
Corporate and Intersegment Eliminations	(2,240)	(2,944)	(1,902)
Total	$1,077,850	$892,191	$818,692
Depreciation and Amortization			
Electric	$40,283	$40,241	$36,946
Wind Energy	10,845	10,363	9,776
Manufacturing	12,936	12,819	12,650
Construction	2,009	2,023	2,010
Plastics	3,377	3,430	2,945
Corporate	550	523	397
Total	$70,000	$69,399	$64,724
Interest Charges			
Electric	$19,643	$20,949	$19,465
Wind Energy	6,852	5,614	2,742
Manufacturing	4,928	4,771	2,791
Construction	947	671	175
Plastics	1,525	1,560	811
Corporate and Intersegment Eliminations	1,923	3,375	2,433
Total	$35,818	$36,940	$28,417
Income (Loss) Before Income Taxes			
Electric	$45,569	$44,505	$34,063
Wind Energy	(26,662)	(22,391)	5,704
Manufacturing	11,164	(18,048)	(7,174)
Construction	(3,688)	(1,115)	1,991
Plastics	9,464	4,007	(126)
Corporate	(16,640)	(18,767)	(15,113)
Total	$19,207	$(11,809)	$19,345
Earnings (Loss) Available for Common Shares			
Electric	$38,886	$34,557	$33,310
Wind Energy	(21,894)	(22,035)	3,487
Manufacturing	7,614	(13,956)	(3,788)
Construction	(2,204)	(646)	1,220
Plastics	5,811	2,515	(59)
Corporate	(11,829)	(11,996)	(10,267)
Total	$16,384	$(11,561)	$23,903
Capital Expenditures			
Electric	$49,707	$43,121	$146,128
Wind Energy	6,057	2,912	10,757
Manufacturing	10,806	6,532	7,912

Construction	2,645	5,490	2,131
Plastics	2,414	2,671	4,269
Corporate	2,048	823	564
Total	$73,677	$61,549	$171,761
Identifiable Assets			
Electric	$1,170,449	$1,106,261	$1,121,241
Wind Energy	149,234	147,975	143,500
Manufacturing	154,908	141,462	159,285
Construction	69,453	60,978	41,455
Plastics	72,200	73,508	70,380
Corporate	54,586	43,102	51,908
Assets of Discontinued Operations	29,692	197,269	166,909
Total	$1,700,522	$1,770,555	$1,754,678

3. Rate and Regulatory Matters

Minnesota

2007 General Rate Case Filing—In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008, OTP was granted an increase in Minnesota retail electric rates of $3.8 million, or approximately 2.9%, which went into effect in February 2009. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% was in effect from November 30, 2007 through January 31, 2009. Amounts refundable totaling $3.9 million had been recorded as a liability on the Company's consolidated balance sheet as of December 31, 2008. An additional $0.5 million refund liability was accrued in January 2009. OTP refunded Minnesota customers the difference between interim and final rates, with interest, in March 2009. In June 2008, OTP deferred recognition of $1.5 million in rate case-related regulatory assessments and fees of outside experts and attorneys that are subject to amortization and recovery over a three-year period beginning in February 2009.

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 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 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.

Renewable Energy Standards, Conservation, Renewable Resource Riders—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'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.

In an order issued on August 15, 2008, the MPUC approved OTP's proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in qualifying renewable energy facilities. The rider enables OTP to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Minnesota Renewable Resource Adjustment (MNRRA) of $0.0019 per kilowatt-hour (kwh) was included on Minnesota customers' electric service statements beginning in September 2008, reflecting cost recovery for OTP's twenty-seven 1.5 megawatt (MW) wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008.

The MPUC approved OTP's petition for a 2009 MNRRA in July 2009, which increased the MNRRA rate to provide cost recovery for OTP's 32 wind turbines at the Ashtabula Wind Energy Center, which became commercially operational in November 2008. This approval increased the 2009 MNRRA to $0.00415 per kwh for the recovery of $6.6 million through March 31, 2010—$4.0 million from August through December 2009 and $2.6 million from January through March 2010. The approval also granted OTP authority to recover over a 48-month period beginning in April 2010 accrued renewable resource recovery revenues that had not previously been recovered.

On January 12, 2010, the MPUC issued an order finding OTP's Luverne Wind Farm project eligible for cost recovery through the 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 Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or 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.

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 Minnesota Department of Commerce (MNDOC) may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under 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. In 2010, OTP recognized $3.7 million in financial incentives relating to 2010, but reduced that amount by $0.2 million in the fourth quarter of 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 relating to 2011.

North Dakota

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 North Dakota Public Service Commission (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 Commission'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.

South Dakota

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 South Dakota Public Utilities Commission (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.

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 customers’ 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.

Federal

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 Construction Work in Progress (CWIP) in rate base and (2) 100% 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, including the Fargo project, Bemidji project and Brookings project.

On December 16, 2010, FERC approved the cost allocation for a new classification of projects in MISO called Multi-Value Projects (MVP). 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, FERC reaffirmed the MVP cost allocation on Rehearing. The MVP cost allocation is currently being challenged at the United States Court of Appeals, 7th Circuit.

On November 3, 2011 OTP filed with 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, 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.

CapX2020 Brookings–Southeast Twin Cities 345 kV Project—In June of 2011, the MISO board of directors granted conditional approval of the Multi-Value Project (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.

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 kiloVolt (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.

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 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.

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. The MISO board of directors granted conditional approval of the MVP cost allocation designation under the MISO Tariff for the Brookings Project, and was granted unconditional approval in December 2011 as an MVP.

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.

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

CapX2020 Request for Advance Determination of Prudence (ADP)—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 November 10, 2011 granting an ADP, conditioned on the MISO MVP cost allocation remaining unchanged.

Big Stone Air Quality Control System

The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to Best Available Retrofit Technology (BART) requirements of the Clean Air Act (CAA), based on air dispersion modeling indicating that Big Stone's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan. Under the U.S. Environmental Protection Agency's (EPA) regional haze regulations, South Dakota developed and submitted its implementation plan and associated implementation rules to the EPA on January 21, 2011. The DENR and 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 developed and submitted its revised implementation plan and associated implementation rules to EPA on September 19, 2011. 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.

On January 14, 2011 OTP filed a petition asking the MPUC for 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 OTP's petition for ADP for the Big Stone Plant Air Quality Control System (AQCS). The MPUC written order was issued 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 of 2012.

Big Stone II Project

On June 30, 2005 OTP and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project's lead developer—from Big Stone II, due to a number of factors. The broad economic downturn, a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations and challenging credit and equity markets made proceeding with Big Stone II and committing to approximately $400 million in capital expenditures untenable for OTP's customers and the Company's shareholders. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

Minnesota—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 $3,199,000 (which excluded $3,246,000 of project transmission-related costs). Because OTP will not earn a return on these deferred costs over the 60-month recovery period, the recoverable amount of $3,199,000 was discounted to its present value of $2,758,000 using OTP's incremental borrowing rate, in accordance with ASC 980, Regulated Operations, accounting requirements.

On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone II transmission facilities. The request asks 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 $3,246,000 Minnesota share of Big Stone II transmission costs to 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.

North Dakota—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, Interveners. The order modified the settlement agreement slightly by using OTP's average 2009 AFUDC rate of 7.65%, rather than OTP's approved rate of return of 8.62% from the NDPSC rate case order of November 25, 2009 as called for by the settlement agreement, to accrue carrying charges during the period from September 1, 2009 to entry of the NDPSC order. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excluded $2,612,000 of project transmission-related costs) was determined to be $10,080,000, of which $4,064,000 represents North Dakota's jurisdictional share.

OTP will include in its total recovery amount a carrying charge of approximately $285,000 on the North Dakota share of Big Stone II generation costs for the period from September 1, 2009 through the date the recovery of costs begins based on OTP's average 2009 AFUDC rate of 7.65%. Because OTP will not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of $4,349,000 was discounted to its present value of $3,913,000 using OTP's incremental borrowing rate, in accordance with ASC 980 accounting requirements. The North Dakota portion of Big Stone II generation costs is being recovered over a 36-month period beginning August 1, 2010.

The North Dakota's jurisdictional share of Big Stone II costs incurred by OTP related to transmission is $1,053,000. 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.

South Dakota—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. Therefore, the South Dakota settlement amount is not discounted. 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.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980, Regulated Operations. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

	December 31, 2011			Remaining Recovery/ Refund
(in thousands)	Current	Long-Term	Total	Period
Regulatory Assets:				
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 6,304	$ 96,074	$ 102,378	see notes
Deferred Marked-to-Market Losses	5,208	10,749	15,957	44 months
Deferred Conservation Improvement Program Costs & Accrued Incentives	5,234	2,208	7,442	18 months
Accrued Cost-of-Energy Revenue	4,043	--	4,043	12 months
Accumulated ARO Accretion/Depreciation Adjustment	--	3,662	3,662	asset lives
Minnesota Renewable Resource Rider Accrued Revenues	1,461	1,306	2,767	33 months
Big Stone II Unrecovered Project Costs – Minnesota	495	2,144	2,639	57 months
Debt Reacquisition Premiums	280	2,246	2,526	249 months
Deferred Income Taxes	--	2,382	2,382	asset lives
Big Stone II Unrecovered Project Costs – North Dakota	1,340	862	2,202	19 months
North Dakota Renewable Resource Rider Accrued Revenues	785	1,325	2,110	24 months
General Rate Case Recoverable Expenses	721	285	1,006	25 months
Big Stone II Unrecovered Project Costs – South Dakota	100	811	911	109 months
North Dakota Transmission Rider Accrued Revenues	518	--	518	12 months
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	343	--	343	11 months
MISO Schedule 26 Transmission Cost Recovery Rider True-up	252	--	252	12 months
Deferred Holding Company Formation Costs	55	83	138	30 months
South Dakota – Asset-Based Margin Sharing Shortfall	138	--	138	2 months
South Dakota Transmission Rider Accrued Revenues	114	--	114	12 months
Total Regulatory Assets	$ 27,391	$ 124,137	$ 151,528	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ --	$ 65,610	$ 65,610	asset lives

Deferred Income Taxes	--	3,379	3,379	asset lives
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	117	123	264 months
Deferred Marked-to-Market Gains	96	--	96	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	54	--	54	12 months
Minnesota Transmission Rider Accrued Refund	28	--	28	see notes
Total Regulatory Liabilities	$ 184	$ 69,106	$ 69,290	
Net Regulatory Asset Position	$ 27,207	$ 55,031	$ 82,238	

(in thousands)	December 31, 2010 Current	Long-Term	Total	Remaining Recovery/ Refund Period
Regulatory Assets:				
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 3,716	$ 70,440	$ 74,156	see notes
Deferred Marked-to-Market Losses	4,370	7,684	12,054	36 months
Minnesota Renewable Resource Rider Accrued Revenues	2,775	4,059	6,834	39 months
Deferred Conservation Improvement Program Costs & Accrued Incentives	3,690	2,965	6,655	18 months
Big Stone II Unrecovered Project Costs – Minnesota	--	6,445	6,445	pending
Deferred Income Taxes	--	5,785	5,785	asset lives
Big Stone II Unrecovered Project Costs – North Dakota	1,258	2,202	3,460	31 months
Debt Reacquisition Premiums	669	2,438	3,107	261 months
Accrued Cost-of-Energy Revenue	2,387	--	2,387	12 months
North Dakota Renewable Resource Rider Accrued Revenues	956	1,459	2,415	36 months
Accumulated ARO Accretion/Depreciation Adjustment	--	2,218	2,218	asset lives
General Rate Case Recoverable Expenses	773	1,000	1,773	40 months
Big Stone II Unrecovered Project Costs – South Dakota	--	1,419	1,419	pending
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	374	343	717	23 months
South Dakota – Asset-Based Margin Sharing Shortfall	462	39	501	14 months
Deferred Holding Company Formation Costs	55	138	193	42 months
Minnesota Transmission Rider Accrued Revenues	--	34	34	15 months
Total Regulatory Assets	$ 21,485	$ 108,668	$ 130,153	
Regulatory Liabilities:				
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ --	$ 61,740	$ 61,740	asset lives
Deferred Income Taxes	--	4,289	4,289	asset lives
Deferred Marked-to-Market Gains	117	58	175	24 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	122	128	276 months
South Dakota – Nonasset-Based Margin Sharing Excess	84	--	84	12 months
Total Regulatory Liabilities	$ 207	$ 66,209	$ 66,416	
Net Regulatory Asset Position	$ 21,278	$ 42,459	$ 63,737	

The regulatory asset related to the unrecognized transition obligation, prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC 715, Compensation—Retirement Benefits, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Gains and Losses recorded as of December 31, 2011 are related to forward purchases of energy scheduled for delivery through August 2015.

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

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

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through 2011 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of December 31, 2011.

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

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 249 months.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with ASC 740, Income Taxes.

Big Stone II Unrecovered Project Costs – North Dakota are the North Dakota share of costs incurred by OTP related to its participation in the abandoned Big Stone II generation project.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2011.

General Rate Case Recoverable Expenses relate to expenses incurred during the rate case proceedings that are eligible for recovery.

Big Stone II Unrecovered Project Costs – South Dakota are the South Dakota share of costs incurred by OTP related to its participation in the abandoned Big Stone II generation project. OTP will be allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted.

North Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facility and net operating costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2011.

MISO Schedule 26 Transmission Cost Recovery Rider True-up relates to the Minnesota jurisdictional portion of MISO Schedule 26 for regional transmission cost recovery that was included in the calculation of the Minnesota Transmission Rider and subsequently adjusted to reflect actual billing amounts in the schedule.

South Dakota – Asset-Based Margin Sharing Shortfall represents differences in OTP's South Dakota share of actual profit margins on wholesale sales of electricity from company-owned generating units and estimated profit margins from those sales that were used in determining current South Dakota retail electric rates. Net asset-based margin sharing accumulated shortfalls will be subject to recovery or refund through future retail rate adjustments in South Dakota.

South Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facility and net operating costs incurred to serve South Dakota customers that have not been billed to South Dakota customers as of December 31, 2011.

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

South Dakota – Nonasset-Based Margin Sharing Excess represents 25% of OTP's South Dakota share of actual profit margins on nonasset-based wholesale sales of electricity. The excess margins accumulated annually will be subject to refund through future retail rate adjustments in South Dakota in the following year.

Minnesota Transmission Rider Accrued Refund relates to revenues from the transmission rider to be refunded to retail customers related to collections on qualifying transmission system facilities and net operating costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of December 31, 2011.

If for any reason, OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an extraordinary expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Forward Contracts Classified as Derivatives

Electricity Contracts
All of OTP's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. OTP's objective in entering into forward contracts for the purchase and sale of energy is to optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and shareholders. OTP's intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. OTP also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.

As of December 31, 2011 OTP had recognized, on a pretax basis, $894,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in ASC 820, Fair Value Measurement.

Electric operating revenues include wholesale electric sales and net unrealized derivative gains on forward energy contracts, the acquisition and settlement of financial transmission rights and congestion revenue rights options in the MISO and Electric Reliability Council of Texas (ERCOT) markets, and daily settlements of virtual transactions in the MISO, ERCOT and California ISO markets, broken down as follows for the years ended December 31:

(in thousands)	2011	2010	2009
Wholesale Sales - Company-Owned Generation	$ 14,518	$ 20,053	$ 12,579
Revenue from Settled Contracts at Market Prices	168,313	147,003	110,124
Market Cost of Settled Contracts	(166,920)	(145,994)	(109,125)
Net Margins on Settled Contracts at Market	1,393	1,009	999
Marked-to-Market Gains on Settled Contracts	10,208	18,901	14,585
Marked-to-Market Losses on Settled Contracts	(10,176)	(17,529)	(13,431)
Net Marked-to-Market Gains on Settled Contracts	32	1,372	1,154
Unrealized Marked-to-Market Gains on Open Contracts	3,707	6,700	8,097
Unrealized Marked-to-Market Losses on Open Contracts	(2,813)	(5,937)	(7,067)
Net Unrealized Marked-to-Market Gains on Open Contracts	894	763	1,030
Wholesale Electric Revenue	$ 16,837	$ 23,197	$ 15,762

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of December 31, 2011 and December 31, 2010, and the change in the Company's consolidated balance sheet position from December 31, 2010 to December 31, 2011 and December 31, 2009 to December 31, 2010:

(in thousands)	December 31, 2011	December 31, 2010
Other Current Asset – Marked-to-Market Gain	$ 3,803	$ 6,875
Regulatory Asset – Current Deferred Marked-to-Market Loss	5,208	4,370
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	10,749	7,684
Total Assets	19,760	18,929
Current Liability – Marked-to-Market Loss	(18,770)	(17,991)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(96)	(117)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	--	(58)
Total Liabilities	(18,866)	(18,166)
Net Fair Value of Marked-to-Market Energy Contracts	$ 894	$ 763

(in thousands)	Year ended December 31, 2011	Year ended December 31, 2010
Fair Value at Beginning of Year	$ 763	$ 1,030
Less: Amounts Realized on Contracts Entered into in 2009	(306)	(389)
Amounts Realized on Contracts Entered into in 2010	(50)	--
Changes in Fair Value of Contracts Entered into in 2009	(14)	--
Changes in Fair Value of Contracts Entered into in 2010	(72)	--
Net Fair Value of Contracts Entered into in Prior Year at Year End	321	641
Changes in Fair Value of Contracts Entered into in Current Year	573	122
Net Fair Value at End of Year	$ 894	$ 763

The $894,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2011 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	1st Qtr 2012	2nd Qtr 2012	3rd Qtr 2012	4th Qtr 2012	Total
Net Gain	$ 511	$ 222	$ 81	$ 80	$ 894

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength.

The following table provides information on OTP's credit risk exposure on delivered and marked-to-market forward contracts as of December 31, 2011 and December 31, 2010:

	December 31, 2011		December 31, 2010	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$1,677	10	$1,129	4
Net Credit Risk to Single Largest Counterparty	$737		$585	

OTP had a net credit risk exposure to ten counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2011 or December 31, 2010 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The credit risk exposures include net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery subsequent to the reporting date. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of December 31, 2011 and December 31, 2010:

Current Liability – Marked-to-Market Loss (in thousands)	December 31, 2011	December 31, 2010
Loss Contracts Covered by Deposited Funds	$ 3,423	$ 427
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade1	15,347	10,904
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	6,660

Total Current Liability – Marked-to-Market Loss	$ 18,770	$ 17,991
1Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions.		
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	$ 15,347	$ 10,904
Offsetting Gains with Counterparties under Master Netting Agreements	(3,471)	(6,219)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$ 11,876	$ 4,685

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6. Common Shares and Earnings Per Share

On May 11, 2009 the Company filed a shelf registration statement with the U.S. Securities and Exchange Commission (SEC) under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement, including common shares of the Company. The Company expects to file a new shelf registration statement prior to the expiration of our existing shelf registration in May 2012.

Common Share Distribution Agreement
On March 17, 2010, the Company entered into a Distribution Agreement (the Agreement) with J.P. Morgan Securities Inc. (JPMS). Pursuant to the terms of the Agreement, the Company may offer and sell its common shares from time to time through JPMS, as the Company's distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75,000,000.

Under the Agreement, the Company will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. Sales of the shares, if any, will be made by means of ordinary brokers' transactions on the NASDAQ Global Select Market at market prices or as otherwise agreed with JPMS. The Company may also agree to sell shares to JPMS, as principal for its own account, on terms agreed by the Company and JPMS in a separate agreement at the time of sale. JPMS will receive from the Company a commission of 2% of the gross sales price per share for any shares sold through it as the Company's distribution agent under the Agreement.

The Company is not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to the Company's existing shelf registration statement, as amended. No shares were sold pursuant to the Agreement in 2011.

Following is a reconciliation of the Company's common shares outstanding from December 31, 2010 through December 31, 2011:

Common Shares Outstanding, December 31, 2010	36,002,739
Issuances:	
Executive Officer Stock Awards on Resignation	88,300
Restricted Stock Issued to Employees	24,600
Restricted Stock Issued to Nonemployee Directors	24,000
Vesting of Restricted Stock Units	17,325
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(55,269)
Common Shares Outstanding, December 31, 2011	36,101,695

Stock Incentive Plan
The 1999 Stock Incentive Plan, as amended (Incentive Plan), provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 3,600,000 common shares are authorized for granting stock awards, of which 1,063,564 were still available as of December 31, 2011 under the Incentive Plan, which terminates on December 13, 2013.

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 73,029 were still available for purchase as of December 31, 2011. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, the Company purchased 78,537 common shares in the open market in 2011, purchased 82,857 common shares in the open market in 2010 and issued 62,450 common shares and purchased 42,611 common shares in the open market in 2009. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive during the investment period for the purpose of calculating diluted earnings per share.

Dividend Reinvestment and Share Purchase Plan
On August 30, 1996 the Company filed a shelf registration statement with the SEC for the issuance of up to 2,000,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders or customers who participate in the Plan to be either new issue common shares or common shares purchased in the open market. The Company’s shelf registration statement expired on December 1, 2011. From November 2004 through April 2009 the Company had purchased common shares in the open market to provide shares for the Plan. From May 2009 through December 2009 the Company issued 233,943 common shares to provide shares for the Plan. In 2010 and 2011 the Company purchased common shares in the open market to provide shares for the Plan.

Earnings Per Share
Basic earnings per common share are calculated by dividing earnings available for common shares by the weighted average number of common shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options. Stock options with exercise prices greater than the market price are excluded from the calculation of diluted earnings per common share. Nonvested restricted shares granted to the Company’s directors and employees are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. Underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share. Shares expected to be awarded for stock performance awards granted to executive officers are considered dilutive for the purpose of calculating diluted earnings per share.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the years ended December 31, 2011, 2010 and 2009:

Year	Options Outstanding	Range of Exercise Prices
2011	156,397	$24.93 – $31.34
2010	383,460	$24.93 – $31.34
2009	415,710	$24.93 – $31.34

7. Share-Based Payments

Purchase Plan
The Purchase Plan allows employees through payroll withholding to purchase shares of the Company’s common stock at a 15% discount from the average market price on the last day of a six month investment period. Under ASC 718, Compensation—Stock Compensation, the Company is required to record compensation expense related to the 15% discount. The 15% discount resulted in compensation expense of $257,000 in 2011, $277,000 in 2010 and $310,000 in 2009. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

Stock Options Granted Under the Incentive Plan
Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company’s common stock. All of the options granted had vested or were forfeited as of December 31, 2007. The exercise price of the options granted was the average market price of the Company’s common stock on the grant date. Under ASC 718 accounting requirements, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under ASC 718 accounting requirements, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan was based on the Black-Scholes option pricing model.

The following table provides information about options outstanding as of December 31, 2011:

	Exercise Price	Outstanding and Exercisable as of 12/31/11	Remaining Contractual Life (yrs)
$	24.93	19,800	3.3
$	26.495	20,100	2.3
$	27.245	52,597	1.3
$	31.34	63,900	0.3

Presented below is a summary of the stock options activity:

Stock Option Activity	2011		2010		2009	
	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	383,460	$27.28	444,810	$26.82	507,702	$26.00
Granted	--	--	--	--	--	--
Exercised	--	--	27,800	19.75	50,350	19.73
Forfeited or Expired	227,063	26.43	33,550	27.38	12,542	21.87
Outstanding, End of Year	156,397	28.53	383,460	27.28	444,810	26.82
Exercisable, End of Year	156,397	28.53	383,460	27.28	444,810	26.82
Cash Received for Options Exercised		--		$549,000		$994,000
Fair Value of Options Granted During Year		none granted		none granted		none granted

Restricted Stock Granted to Directors

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 11, 2011 the Company's Board of Directors granted 24,000 shares of restricted stock to the Company's nonemployee directors. The restricted shares vest 25% per year on April 8 of each year in the period 2012 through 2015 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $22.51 per share, the average market price on the date of grant.

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

Directors' Restricted Stock Awards	2011		2010		2009	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	59,725	$24.95	54,300	$27.81	39,300	$33.45
Granted	24,000	22.51	24,800	21.835	28,800	22.15
Vested	29,475	26.07	19,375	28.98	13,800	32.06
Forfeited	--		--		--	
Nonvested, End of Year	54,250	23.26	59,725	24.95	54,300	27.81
Compensation Expense Recognized		$740,000		$595,000		$535,000
Fair Value of Shares Vested in Year		768,000		561,000		442,000

Restricted Stock Granted to Employees

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 11, 2011 the Company's Board of Directors granted 24,600 shares of restricted stock to the Company's executive officers and OTP's president, under the Incentive

Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2012 through 2015 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $22.51 per share, the average market price on the date of grant.

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

Employees' Restricted Stock Awards	2011		2010		2009	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Nonvested, Beginning of Year	66,161	$24.79	50,478	$28.31	34,146	$34.72
Granted	24,600	22.51	31,600	21.83 5	27,600	22.15
Variable/Liability Awards Vested	--		--		2,250	22.91
Nonvariable Awards Vested	55,893	25.00	15,917	29.76	9,018	35.84
Forfeited	--		--		--	
Nonvested, End of Year	34,868	22.86	66,161	24.79	50,478	28.31
Compensation Expense Recognized		$832,000		$914,000		$439,000
Fair Value of Variable Awards Vested/Liability Paid		--		--		52,000
Fair Value of Nonvariable Awards Vested		1,397,000		474,000		323,000

Restricted Stock Units Granted to Employees

On April 11, 2011 the Company's Board of Directors granted 19,800 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2015, the date the units vest. The grant date fair value of each restricted stock unit was $18.03 per share based on the market value of the Company's common stock on April 11, 2011, discounted for the value of the dividend exclusion over the four-year vesting period. The weighted average contractual term of stock units outstanding as of December 31, 2011 is 2.4 years.

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

Employees' Restricted Stock Unit Awards	2011		2010		2009	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	79,315	$23.55	92,670	$25.42	73,585	$28.13
Granted	19,800	18.03	26,180	17.76	29,515	18.86
Converted	20,025	27.94	18,965	23.93	5,350	24.94
Forfeited	5,275	22.56	20,570	25.55	5,080	27.33
Nonvested, End of Year	73,815	20.95	79,315	23.55	92,670	25.42
Compensation Expense Recognized		$349,000		$250,000		$543,000
Fair Value of Units Converted in Year		559,000		454,000		133,000

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company’s executive officers. Under these agreements, the officers could be awarded shares of the Company’s common stock based on the Company’s total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under ASC 718 accounting requirements, the amount of compensation expense recorded related to awards granted is based on the estimated grant-date fair value of the awards as determined under a Monte Carlo valuation method for awards granted prior to 2009. The offsetting credit to amounts expensed related to the stock performance awards granted prior to 2009 is included in common shareholders’ equity. The terms of the awards granted after 2008 are such that the entire award will be classified and accounted for as a liability, as required under ASC 718 and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

On April 11, 2011 the Company’s Board of Directors granted performance share awards to the Company’s executive officers under the Incentive Plan for the 2011-2013 performance measurement period.

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

Performance Period	Maximum Shares Subject To Award	Shares Used To Estimate Expense	Fair Value	Expense Recognized in the Year Ended December 31, 2011	2010	2009	Shares Awarded
2011-2013	97,200	48,600	$23.61	$553,000	$--	$--	26,100
2010-2012	146,800	73,400	$20.97	572,000	513,000	--	49,500
2009-2011	181,200	90,600	$27.98	746,000	(178,000)	845,000	64,500
2008-2010	114,800	70,843	$37.59	--	888,000	888,000	18,600
2007-2009	109,000	67,263	$38.01	--	--	852,000	34,768
Total				$1,871,000	$1,223,000	$2,585,000	193,468

The Company's former Chief Executive Officer resigned his employment with the Company effective December 15, 2011, and his resignation was treated as a termination without cause for the purposes of his employment agreement. Under the terms of his employment agreement, he received the targeted number of the Company's common shares for the performance awards granted him in 2009, 2010 and 2011, or 88,300 shares, valued at the average of the high and low price of the Company's common shares on December 14, 2011 of $21.191 per share, for a total value of $1,871,165.

The Company's former Chief Operating Officer resigned his employment with the Company effective December 30, 2010 with good reason as that term is defined in his employment agreement. Under the terms of his employment agreement, he received the targeted number of the Company's common shares for the performance awards granted him in 2008, 2009 and 2010, or 70,400 shares, valued at the average of the high and low price of the Company's common shares on December 30, 2010 of $22.78 per share, for a total value of $1,603,712.

The shares awarded shown in the table above for the 2008-2010, 2009-2011, 2010-2012 and 2011-2013 performance periods reflect only shares received under the executive employment agreements. The Company's 2008-2010 and 2009-2011 total shareholder return rankings resulted in no incentive share awards for the Company's active plan participants for the 2008-2010 and 2009-2011 performance measurement periods.

The expense recorded in 2010 related to the 2008-2010 performance measurement period reflects one-third of the grant-date fair value of the total targeted number of awards for that performance period. The expense recorded in 2010 related to the 2009-2011 performance measurement period liability awards reflects the December 31, 2010 fair value of these awards, estimated to be $0, which resulted in a reversal of the $845,000 expense accrued in 2009, plus the December 30, 2010 market value of the former Chief Operating Officer's 2009-2011 targeted share awards of $667,000. The expense recorded in 2010 related to the 2010-2012 performance measurement period liability awards reflects the December 31, 2010 fair value of these awards, estimated to be $0, plus the December 30, 2010 market value of the former Chief Operating Officer's 2010-2012 targeted share awards of $513,000.

As of December 31, 2011 the total remaining unrecognized amount of compensation expense related to stock-based compensation for all of the Company's stock-based payment programs was approximately $2.0 million (before income taxes), which will be amortized over a weighted-average period of 2.5 years.

8. Retained Earnings Restriction

The Company's Restated Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company’s cumulative preferred shares. Under these provisions none of the Company’s retained earnings were restricted at December 31, 2011.

9. Commitments and Contingencies

At December 31, 2011 OTP had commitments under contracts in connection with construction programs aggregating approximately $40,910,000. OTP has commitments for the purchase of capacity and energy requirements under agreements extending through 2032. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2012 and 2016. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings, construction equipment and vehicles. Rent expense from continuing operations was $13,563,000, $13,401,000 and $11,769,000 for 2011, 2010 and 2009, respectively.

The amounts of the Company's commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of December 31, 2011, are as follows:

(in thousands)	Capacity and Energy Requirements	Coal and Freight Purchase Commitments	Operating Leases OTP	Operating Leases Nonelectric	Total
2012	$ 33,116	$ 52,125	$ 2,024	$ 6,798	$ 8,822
2013	29,001	10,274	1,214	5,435	6,649
2014	16,000	10,274	1,224	4,212	5,436
2015	13,807	10,274	1,236	3,738	4,974
2016	7,686	3,508	1,201	3,653	4,854
Beyond 2016	74,219	--	13,750	6,900	20,650
Total	$ 173,829	$ 86,455	$ 20,649	$ 30,736	$ 51,385

Other

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2011 will not be material.

Contingencies, by their nature, relate to uncertainties that require the Company's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies impacting the Company's consolidated financial statements are those related to product warranty, environmental remediation, litigation matters, possible liquidated damages and the resolution of matters related to open tax years. Should any of these items result in a liability being incurred, the range of loss could be as high as $9.0 million. Additionally, the Company may become subject to significant claims of which its management is unaware, or the claims of which its management is aware may result in the Company incurring a significantly greater liability than it anticipates.

10. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of the Company's lines of credit as of December 31, 2011 and December 31, 2010:

(in thousands)	Line Limit	In Use on December 31, 2011	Restricted due to Outstanding Letters of Credit	Available on December 31, 2011	Available on December 31, 2010
Otter Tail Corporation Credit Agreement	$200,000	$--	$1,224	$198,776	$144,350
OTP Credit Agreement	170,000	--	4,050	165,950	144,436
Total	$370,000	$--	$5,274	$364,726	$288,786

Under the Otter Tail Corporation Credit Agreement, the maximum amount of debt outstanding in 2011 was $112,945,000 on April 22, 2011 and the average daily balance of debt outstanding during 2011 was $40,624,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2011 was 3.7% compared with 3.4% in 2010. Under the OTP Credit Agreement, the maximum amount of debt outstanding in 2011 was $30,672,000 on February 18, 2011 and the average daily balance of debt outstanding during 2011 was $16,087,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2011 was 1.5% compared with 0.8% in 2010. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2010 was 2.6%.

On May 4, 2010 the Company entered into a $200 million Second Amended and Restated Credit Agreement (the Credit Agreement), which is an unsecured revolving credit facility that the Company can draw on to support its nonelectric operations. Borrowings under the Credit Agreement bear interest at LIBOR plus 3.25%, subject to adjustment based on the Company’s senior unsecured credit ratings. The Credit Agreement expires on May 4, 2013. The Credit Agreement contains a number of restrictions on the Company and the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Credit Agreement also contains affirmative covenants and events of default. The Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company’s credit ratings. The Company’s obligations under the Credit Agreement are guaranteed by certain of the Company’s material subsidiaries. Outstanding letters of credit issued by the Company under the Credit Agreement can reduce the amount available for borrowing under the line by up to $50 million. The Credit Agreement has an accordion feature whereby the line can be increased to $250 million as described in the Credit Agreement.

On March 3, 2011 OTP entered into an Amended and Restated Credit Agreement (the OTP Credit Agreement) that provides for a $170 million line of credit that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under the line of credit currently bear interest at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP’s senior unsecured debt. Under the OTP Credit Agreement OTP is required to pay the Banks’ commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement expires on March 3, 2016.

The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. The OTP Credit Agreement amends and restates the $170 million Credit Agreement dated as of July 30, 2008 among OTP (formerly known as Otter Tail Corporation, dba Otter Tail Power Company), the Banks named therein, as amended by a First Amendment to Credit Agreement dated as of April 21, 2009 and a Second Amendment to Credit Agreement dated as of June 22, 2009.

Long-Term Debt

On May 11, 2009 the Company filed a shelf registration statement with the SEC under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement.

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

Senior Unsecured Notes 4.63%, due December 1, 2021

On December 1, 2011, OTP issued $140 million aggregate principal amount of OTP’s 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes) pursuant to a Note Purchase Agreement (the 2011 Note Purchase Agreement), dated as of July 29, 2011, with the purchasers named therein.

Debt Retirements

On December 1, 2011 OTP used a portion of the proceeds from the 2021 Notes to retire $90 million aggregate principal amount of its 6.63% Senior Notes due December 1, 2011 at maturity and to retire early $10.4 million aggregate principal amount of its pollution control refunding revenue bonds due December 1, 2012. No penalty was paid for the early retirement.

2007 and 2011 Note Purchase Agreements

The note purchase agreement relating to OTP's $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037, as amended (the 2007 Note Purchase Agreement) and the 2011 Note Purchase Agreement each states that the applicable obligor may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the applicable obligor to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreements. The 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement each also states OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement each contains a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor's ability and the ability of the obligor's subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

Cascade Note Purchase Agreement

The Note Purchase Agreement dated as of February 23, 2007 with Cascade Investment, L.L.C., as amended (the Cascade Note Purchase Agreement), states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The Cascade Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the Cascade Note Purchase Agreement. The Cascade Note Purchase Agreement contains a number of restrictions on the businesses of the Company and its subsidiaries. These include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. In addition, the interest rate applicable to the Cascade Note was increased to 8.89% per annum which is reflective of the Company's new senior unsecured debt ratings. The obligations of the Company under the Cascade Note Purchase Agreement and the Cascade Note are guaranteed by Varistar Corporation and certain of its subsidiaries. Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2011.

On June 23, 2010 the Company entered into Amendment No. 3 to the Cascade Note Purchase Agreement. Amendment No. 3 amends certain covenants and related definitions contained in the Cascade Note Purchase Agreement to, among other things, provide the Company and its material subsidiaries with additional flexibility to incur certain customary liens, make certain investments, and give certain guaranties, in each case under the circumstances set forth in Amendment No. 3. On July 29, 2010 the Company entered into Amendment No. 4 to the

Cascade Note Purchase Agreement, which was effective June 30, 2010. The amendments contained in Amendment No. 4 permit the Company to exclude impairment charges and write-offs of assets (including ShoreMaster's June 2010 asset impairment charge), from the calculation of the interest charges coverage ratio required to be maintained under the Cascade Note Purchase Agreement. On December 12, 2011 the Company entered into Amendment No. 5 to the Cascade Note Purchase Agreement which permits the Company to exclude gains or losses from the sales of subsidiaries.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2011 for each of the next five years are:

(in thousands)	2012	2013	2014	2015	2016
Aggregate amounts of Debt Maturities	$3,033	$214	$222	$230	$100,239

The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of December 31, 2011 and December 31, 2010:

December 31, 2011 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$--	$--	$--	$--
Long-Term Debt:				
9.000% Notes, due December 15, 2016			$100,000	$100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	$33,000			33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,090			5,090
Senior Unsecured Note 8.89%, due November 30, 2017			50,000	50,000
Senior Unsecured Notes 4.63%, due December 1, 2021	140,000			140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,105			20,105
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Other Obligations - Various up to 3.95% at December 31, 2011		$2,868	1,889	4,757
Total	$320,195	$2,868	$151,889	$474,952
Less: Current Maturities	--	2,868	165	3,033
Unamortized Debt Discount	--	--	4	4
Total Long-Term Debt	$320,195	$--	$151,720	$471,915
Total Short-Term and Long-Term Debt (with current maturities)	$320,195	$2,868	$151,885	$474,948

December 31, 2010 (in thousands)	OTP	Varistar	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$25,314	$--	$54,176	$79,490
Long-Term Debt:				
Senior Unsecured Notes 6.63%, due December 1, 2011	$90,000			$90,000
Pollution Control Refunding Revenue Bonds, Variable, 2.50% at December 31, 2010, due December 1, 2012, retired December 1, 2011	10,400			10,400
9.000% Notes, due December 15, 2016			$100,000	100,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000			33,000

Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,100			5,100
Senior Unsecured Note 8.89%, due November 30, 2017			50,000	50,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000			30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,215			20,215
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000			42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000			50,000
Other Obligations - Various up to 13.31% at December 31, 2010		$3,190		3,190
Total	$280,715	$3,190	$150,000	$433,905
Less: Current Maturities	--	224	--	224
Unamortized Debt Discount	--	--	5	5
Total Long-Term Debt	$280,715	$2,966	$149,995	$433,676
Total Short-Term and Long-Term Debt (with current maturities)	$306,029	$3,190	$204,171	$513,390

Financial Covenants

As of December 31, 2011 the Company was in compliance with the financial statement covenants that existed in its debt agreements.

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

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

- Under the Otter Tail Corporation Credit Agreement, the Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Otter Tail Corporation Credit Agreement.

- Under the Cascade Note Purchase Agreement, the Company may not permit its ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or its Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement. In addition, under the Cascade Note Purchase Agreement, as amended, the Company may not permit the aggregate principal amount of all Debt of OTP and its subsidiaries to exceed 60% of Otter Tail Consolidated Total Capitalization (as defined in the Cascade Note Purchase Agreement, as amended by Amendment No. 2), determined as of the end of each fiscal quarter of the Company.

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the OTP Credit Agreement.

- Under the 2007 Note Purchase Agreement, 2011 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

11. Class B Stock Options of Subsidiary

In conjunction with the sale of IPH on May 6, 2011, all 363 outstanding IPH Class B common share options were cancelled by mutual agreement between the issuer and the holders of the options and a liability to the holders of the options was established based on the fair value of the options on May 6, 2011. The liability was assumed by the new owner of IPH. The options were adjusted to their fair value based on the fair value of an underlying share of Class B Common Stock of $2,973.90 per share on May 6, 2011. The book value of IPH Class B common share options prior to their cancellation on May 6, 2011 was based on an IPH Class B common share value of $2,085.88 per share. The $322,000 difference between the fair value and book value of the options was charged to retained earnings and earnings available for common shares were reduced by $322,000 in the second quarter of 2011.

12. Pension Plan and Other Postretirement Benefits

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

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

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

Components of net periodic pension benefit cost:

(in thousands)	2011	2010	2009
Service Cost--Benefit Earned During the Period	$4,415	$4,654	$4,180
Interest Cost on Projected Benefit Obligation	12,666	12,067	11,943
Expected Return on Assets	(14,140)	(13,711)	(13,779)
Amortization of Prior-Service Cost	434	683	724
Amortization of Net Actuarial Loss	2,617	2,002	77
Net Periodic Pension Cost	$5,992	$5,695	$3,145

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

	2011	2010	2009
Discount Rate	6.00 %	6.00 %	6.70 %
Long-Term Rate of Return on Plan Assets	8.00 %	8.50 %	8.50 %
Rate of Increase in Future Compensation Level	3.75 %	3.75 %	3.75 %

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

(in thousands)	2011	2010
Regulatory Assets:		
Unrecognized Prior Service Cost	$1,507	$1,930
Unrecognized Actuarial Loss	89,820	64,396
Total Regulatory Assets	91,327	66,326
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	28	35
Unrecognized Actuarial Loss	1,131	667
Total Accumulated Other Comprehensive Loss	1,159	702
Deferred Income Taxes	772	468
Noncurrent Liability	$77,495	$45,741

Funded status as of December 31:

(in thousands)	2011	2010
Accumulated Benefit Obligation	$(211,324)	$(183,174)
Projected Benefit Obligation	$(246,098)	$(217,049)
Fair Value of Plan Assets	168,603	171,308
Funded Status	$(77,495)	$(45,741)

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

(in thousands)	2011	2010
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$171,308	$140,547
Actual Return on Plan Assets	6,764	19,883
Discretionary Company Contributions	--	20,000
Benefit Payments	(9,469)	(9,122)
Fair Value of Plan Assets at December 31	$168,603	$171,308
Estimated Asset Return	4.06%	13.62%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$217,049	$207,145
Service Cost	4,415	4,654
Interest Cost	12,666	12,067
Benefit Payments	(9,469)	(9,122)
Actuarial Loss	21,437	2,305
Projected Benefit Obligation at December 31	$246,098	$217,049

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

	2011	2010
Discount Rate	5.15%	6.00%
Rate of Increase in Future Compensation Level	3.38%	3.75%

The assumed rate of return on pension fund assets used for the determination of 2012 net periodic pension cost is 8.00%. The assumed long-term rate of return on plan assets is based primarily on asset category studies using historical market return and volatility data with forward looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically. We review our rate of return on plan asset assumptions annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with our pension plan investment advisors, as well as input from actuaries who work with the pension plan.

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

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

Measurement Dates:	2011	2010
Net Periodic Pension Cost	January 1, 2011	January 1, 2010

End of Year Benefit Obligations	January 1, 2011 projected to December 31, 2011	January 1, 2010 projected to December 31, 2010
Market Value of Assets	December 31, 2011	December 31, 2010

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2012 are:

(in thousands)	2012
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$398
Amortization of Unrecognized Actuarial Loss	4,656
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	11
Amortization of Unrecognized Actuarial Loss	124
Total Estimated Amortization	$5,189

Cash flows—The Company had a minimum funding requirement of $3,015,000 as of December 31, 2011, and made a plan contribution of $10,000,000 in January 2012.

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

(in thousands)	2012	2013	2014	2015	2016	Years 2017-2021
	$10,286	$10,587	$10,956	$11,478	$12,049	$73,560

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

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of the Company.
- The Plan's assets should be invested with the objective of meeting current and future payment requirements while minimizing annual contributions and their volatility.
- The asset strategy reflects the desire to meet current and future benefit payments while considering a prudent level of risk and diversification.

The asset allocation strategy developed by the Company's Benefits Advisory Committee (BAC) is based on the current needs of the Plan, the investment objectives listed above, the investment preferences and risk tolerance of the committee and a desired degree of diversification.

The asset allocation strategy contains guideline percentages, at market value, of the total Plan invested in various asset classes. The strategic target allocation and the tactical range shown in the table that follows is a guide that will at times not be reflected in actual asset allocations that may be dictated by prevailing market conditions, independent actions of the BAC and/or investment manager, and required cash flows to and from the Plan. The tactical range provides flexibility for the investment manager's portfolio to vary around the target allocation without the need for immediate rebalancing.

Allocation targets and tactical ranges shown below reflect the Investment Policy Statement approved by the BAC. Each of the asset categories is within its respective tactical range. The Investment Subcommittee of the BAC monitors actual asset allocations and directs contributions and withdrawals toward maintaining the current targeted allocation percentages listed below.

Asset Allocation	Strategic Target	Tactical Range

Equity Securities	51	%	41%-61	%
Fixed-Income Securities	44	%	34%-54	%
Enhanced Return	5	%	0%-12	%
Cash	0	%	0%-5	%

The Company's pension plan asset allocations at December 31, 2011 and 2010, by asset category are as follows:

Asset Allocation	2011		2010	
Large Capitalization Equity Securities	25.7	%	26.7	%
International Equity Securities	14.4	%	16.8	%
Small and Mid Capitalization Equity Securities	6.9	%	7.0	%
SEI Special Situation Collective Investment Trust	4.8	%	--	
Equity Securities	51.8	%	50.5	%
Fixed-Income Securities and Cash	43.4	%	49.5	%
Other – SEI Institutional Investment Trust – Dynamic Asset Allocation	4.8	%	--	
	100.0	%	100.0	%

Fair Value Measurements of Pension Fund Assets
ASC 715, Compensation – Retirement Benefits, requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 – Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following table presents, for each of these hierarchy levels, the Company's pension fund assets measured at fair value as of December 31, 2011 and 2010:

2011 (in thousands)	Level 1	Level 2	Level 3
Large Capitalization Equity Securities	$43,334		
International Equity Securities	24,294		
Small and Mid Capitalization Equity Securities	11,567		
SEI Special Situation Collective Investment Trust			$8,131
Fixed Income Securities	72,233		
Other – SEI Institutional Investment Trust – Dynamic Asset Allocation	8,133		
Cash Management – Working Capital Account		$911	
Total Assets	$159,561	$911	$8,131

2010 (in thousands)		Level 1	Level 2	Level 3
Large Capitalization Equity Securities	$	45,861		
International Equity Securities		28,755		

Small and Mid Capitalization Equity Securities		11,963		
Fixed Income Securities		75,447		
Cash Management – Working Capital Accounts		8,403	$	879
Total Assets	$	170,429	$	879

The Company's level 3 investments in the SEI Special Situation Collective Investment Trust consist of investments primarily in hedge funds that pursue alternative strategies, private equity funds and hybrid funds, as well as investments directly in other securities and financial instruments, with the objective of achieving high returns balanced against an appropriate level of volatility and market exposure over a full market cycle. The net asset value of the SEI Special Situations Collective Investment Trust is determined by using the fair value of the portfolio as of the close of business at the end of the year. The fair value of the fund is calculated independently by the fund's administrator and is reviewed by the management team. There were no significant transfers between Levels 1, 2 or 3 during the year ended December 31, 2011. The Company's initial investment in the SEI Special Situation Collective Investment Trust was made in January 2011.

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

Components of net periodic pension benefit cost:

(in thousands)	2011	2010	2009
Service Cost–Benefit Earned During the Period	$81	$660	$752
Interest Cost on Projected Benefit Obligation	1,632	1,670	1,694
Amortization of Prior Service Cost	73	74	71
Amortization of Net Actuarial Loss	245	477	385
Net Periodic Pension Cost	$2,031	$2,881	$2,902

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

	2011	2010	2009
Discount Rate	6.00 %	6.00 %	6.70 %
Rate of Increase in Future Compensation Level	4.65 %	4.69 %	4.70 %

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

(in thousands)	2011	2010
Regulatory Assets:		
Unrecognized Prior Service Cost	$215	$343
Unrecognized Actuarial Loss	2,427	3,024
Total Regulatory Assets	2,642	3,367
Projected Benefit Obligation Liability – Net Amount Recognized	(29,323)	(27,797)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	184	151
Unrecognized Actuarial Loss	2,067	1,324
Total Accumulated Other Comprehensive Loss	2,251	1,475
Deferred Income Taxes	1,500	984
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(22,930)	$(21,971)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan’s projected benefit obligations over the two-year period ended December 31, 2011 and a statement of the funded status as of December 31 of both years:

(in thousands)	2011	2010
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Employer Contributions	1,072	1,067
Benefit Payments	(1,072)	(1,067)
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		

Projected Benefit Obligation at January 1	$27,797	$28,441
Service Cost	81	660
Interest Cost	1,632	1,670
Benefit Payments	(1,072)	(1,067)
Plan Amendments	--	--
Actuarial (Gain) Loss	885	(1,907)
Projected Benefit Obligation at December 31	$29,323	$27,797
Reconciliation of Funded Status:		
Funded Status at December 31	$(29,323)	$(27,797)
Unrecognized Net Actuarial Loss	5,872	5,232
Unrecognized Prior Service Cost	521	594
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(22,930)	$(21,971)

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

	2011	2010
Discount Rate	5.15 %	6.00 %
Rate of Increase in Future Compensation Level	4.59 %	4.65 %

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2012 are:

(in thousands)	2012
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$22
Amortization of Unrecognized Actuarial Loss	100
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	51
Amortization of Unrecognized Actuarial Loss	227
Total Estimated Amortization	$400

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

(in thousands)	2012	2013	2014	2015	2016	Years 2017-2021
	$1,128	$1,243	$1,252	$1,421	$1,418	$7,387

Other Postretirement Benefits

The Company provides a portion of health insurance and life insurance benefits for retired OTP and corporate employees. Substantially all of the Company's electric utility and corporate employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. On adoption of Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, in January 1993, the Company elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years. There are no plan assets.

Components of net periodic postretirement benefit cost:

(in thousands)	2011	2010	2009
Service Cost–Benefit Earned During the Period	$1,524	$1,634	$1,172
Interest Cost on Projected Benefit Obligation	3,418	3,207	2,935
Amortization of Transition Obligation	748	748	748
Amortization of Prior Service Cost	211	211	211
Amortization of Net Actuarial Loss	835	832	--
Expense Decrease Due to Medicare Part D Subsidy	(2,118)	(2,078)	(1,335)
Net Periodic Postretirement Benefit Cost	$4,618	$4,554	$3,731

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

	2011	2010	2009
Discount Rate	5.75 %	5.75 %	6.70 %

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

(in thousands)	2011	2010
Regulatory Asset:		
Unrecognized Transition Obligation	$723	$727
Unrecognized Prior Service Cost	950	1,155
Unrecognized Net Actuarial Loss	6,736	2,580
Net Regulatory Asset	8,409	4,462
Projected Benefit Obligation Liability – Net Amount Recognized	(48,263)	(42,372)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	15	462
Unrecognized Prior Service Cost	17	21
Unrecognized Net Actuarial Loss (Gain)	4	(82)
Accumulated Other Comprehensive Loss	36	401
Deferred Income Taxes	24	267
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(39,794)	$(37,242)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2011:

(in thousands)	2011	2010
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Company Contributions	2,066	1,769
Benefit Payments (Net of Medicare Part D Subsidy)	(4,119)	(3,748)
Participant Premium Payments	2,053	1,979
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$42,372	$37,712
Service Cost (Net of Medicare Part D Subsidy)	1,275	1,371
Interest Cost (Net of Medicare Part D Subsidy)	2,384	2,224
Benefit Payments (Net of Medicare Part D Subsidy)	(4,119)	(3,748)
Participant Premium Payments	2,053	1,979
Actuarial Loss	4,298	2,834
Projected Benefit Obligation at December 31	$48,263	$42,372
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$(37,242)	$(34,457)
Expense	(4,618)	(4,554)
Net Company Contribution	2,066	1,769
Accrued Postretirement Cost at December 31	$(39,794)	$(37,242)

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

	2011	2010
Discount Rate	5.05%	5.75%

Assumed healthcare cost-trend rates as of December 31:

	2011		2010	
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.78	%	6.94	%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.21	%	7.42	%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00	%	5.00	%
Year the Rate Reaches the Ultimate Trend Rate	2025		2025	

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2011 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$5,802	$(4,832)
Effect on Total of Service and Interest Cost	$567	$(457)
Effect on Expense	$857	$(457)

Measurement Dates:	2011	2010
Net Periodic Postretirement Benefit Cost	January 1, 2011	January 1, 2010
End of Year Benefit Obligations	January 1, 2011 projected to December 31, 2011	January 1, 2010 projected to December 31, 2010

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2012 are:

(in thousands)	2012
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$729
Amortization of Unrecognized Prior Service Cost	205
Amortization of Unrecognized Actuarial Loss	219
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	19
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Loss	6
Total Estimated Amortization	$1,183

Cash flows—The Company expects to contribute $2.5 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2012. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $543,000 in 2012. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2012	2013	2014	2015	2016	Years 2017-2021
	$2,522	$2,635	$2,774	$2,884	$3,039	$17,931

401K Plan

The Company sponsors a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans by the Company and its subsidiary companies totaled $3,386,000 for 2011, $3,172,000 for 2010 and $3,605,000 for 2009.

Employee Stock Ownership Plan

The Company has a stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $760,000 for 2011, $779,000 for 2010 and $761,000 for 2009.

13. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash and Short-Term Investments—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Long-Term Debt—The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. The Company’s long-term debt subject to variable interest rates approximates fair value.

	December 31, 2011		December 31, 2010	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$14,652	$14,652	$--	$--
Long-Term Debt	(471,915)	(525,041)	(433,676)	(473,171)

14. Property, Plant and Equipment

(in thousands)	December 31, 2011	December 31, 2010
Electric Plant in Service		
Production	$669,805	$660,488
Transmission	229,320	218,221
Distribution	390,383	373,180
General	83,026	81,085
Electric Plant in Service	1,372,534	1,332,974
Construction Work in Progress	49,123	27,788
Total Gross Electric Plant	1,421,657	1,360,762
Less Accumulated Depreciation and Amortization	499,327	476,188
Net Electric Plant	$922,330	$884,574
Nonelectric Operations Plant		
Equipment	$208,478	$190,773
Buildings and Leasehold Improvements	88,639	81,492
Land	13,203	16,214
Nonelectric Operations Plant	310,320	288,479
Construction Work in Progress	5,316	14,188
Total Gross Nonelectric Plant	315,636	302,667
Less Accumulated Depreciation and Amortization	160,417	138,172
Net Nonelectric Operations Plant	$155,219	$164,495
Net Plant	$1,077,549	$1,049,069

The estimated service lives for rate-regulated properties is 5 to 70 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

	Service Life Range	
(years)	Low	High
Electric Fixed Assets:		

Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	70
Nonelectric Fixed Assets:		
Equipment	3	12
Buildings and Leasehold Improvements	7	40

15. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2011, 2010 and 2009) to net income before total income tax expense for the following reasons:

(in thousands)	2011		2010		2009	
Tax Computed at Federal Statutory Rate	$6,722		$(4,133	)	$6,771	
Increases (Decreases) in Tax from:						
Income Taxes on Valuation Allowances	3,712		5,549		--	
Foreign Rate Differential/True-up	1,422		1,081		--	
State Income Taxes Net of Federal Income Tax Benefit	877		(1,760	)	1,790	
Differences Reversing in Excess of Federal Rates	680		989		893	
Book Write-off of Intangible Impairment	--		3,309		--	
Federal Production Tax Credit	(7,281	)	(6,441	)	(6,533	)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(996	)	(1,163	)	(870	)
Investment Tax Credit Amortization	(855	)	(926	)	(992	)
Dividend Received/Paid Deduction	(677	)	(692	)	(683	)
Impact of Medicare Part D Change	(599	)	1,692		--	
Tax Depreciation - Treasury Grant for Wind Farms	(507	)	(845	)	(3,169	)
Corporate Owned Life Insurance	(388	)	(556	)	(973	)
Allowance for Funds Used During Construction - Equity	(301	)	(1	)	(1,113	)
Permanent and Other Differences	278		2,914		(415	)
Total Income Tax Expense (Benefit)	$2,087		$(983	)	$(5,294	)
Income Tax (Benefit) Expense – Discontinued Operations	$(11,370	)	$4,934		$689	
Overall Effective Federal, State and Foreign Income Tax Rate	41.2	%	151.5	%	(21.5	)%
Income Tax Expense Includes the Following:						
Current Federal Income Taxes	$(8,084	)	$(16,464	)	$(48,412	)
Current State Income Taxes	(1,700	)	2,871		3,360	
Deferred Federal Income Taxes	16,338		20,729		48,955	
Deferred State Income Taxes	4,509		(3,806	)	(583	)
Foreign Income Taxes	156		4,217		(219	)
Federal Production Tax Credit	(7,281	)	(6,441	)	(6,533	)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(996	)	(1,163	)	(870	)
Investment Tax Credit Amortization	(855	)	(926	)	(992	)
Total	$2,087		$(983	)	$(5,294	)
(Loss) Income Before Income Taxes – U.S.	$(7,547	)	$13,670		$22,060	
Loss Before Income Taxes – Foreign	(14,979	)	(11,063	)	(634	)
Total Income Before Income Taxes	$(22,526	)	$2,607		$21,426	

The Company's deferred tax assets and liabilities were composed of the following on December 31:

(in thousands)	2011	2010
Deferred Tax Assets		

Related to North Dakota Wind Tax Credits	$44,370	$57,564
Benefit Liabilities	37,402	35,426
Retirement Benefits Liabilities	27,214	29,092
Cost of Removal	25,777	24,326
Federal Production Tax Credits	20,354	13,072
Differences Related to Property	10,227	11,628
Net Operating Loss Carryforward (Net of Valuation Allowance $9,262 for 2011; $5,549 for 2010)	8,389	11,243
Amortization of Tax Credits	3,379	4,290
Vacation Accrual	2,414	2,563
Other	9,630	7,959
Total Deferred Tax Assets	$189,156	$197,163
Deferred Tax Liabilities		
Differences Related to Property	$(294,395)	$(269,021)
Retirement Benefits Regulatory Asset	(27,214)	(29,092)
Related to North Dakota Wind Tax Credits	(11,850)	(15,132)
Excess Tax over Book Pension	(6,353)	(8,656)
Impact of State Net Operating Losses on Federal Taxes	(2,710)	(1,992)
Transfer to Regulatory Asset	(1,969)	(7,920)
Renewable Resource Rider Accrued Revenue	(1,913)	(3,625)
Other	(7,709)	(7,133)
Total Deferred Tax Liabilities	$(354,113)	$(342,571)
Deferred Income Taxes	$(164,957)	$(145,408)

Schedule of expiration of tax net operating losses and tax credits available as of December 31, 2011:

		Year of Expiration					
(in thousands)	Amount	2012	2013	2014	2015	2016	2024-33
United States							
Federal Net Operating Losses	$4,975	$--	$--	$--	$--	$--	$4,975
Federal Tax Credits	21,437	--	--	--	--	--	21,437
State Net Operating Losses	9,747	--	--	--	--	--	9,747
State Tax Credits	43,172	511	1,950	1,950	1,950	1,950	34,861
Canada							
Net Operating Losses	7,914	--	--	--	--	--	7,914

As of December 31, 2011, the Company has recorded a valuation allowance related to Canadian net operating loss carryforwards. The valuation allowance represents a provision for uncertainty as to the realization of the tax benefits of these carryforwards. The valuation allowance will be reduced when and if the Company determines it is more likely than not that the related deferred income tax assets will be realized. The carryforward period on a portion of the North Dakota wind tax credits from the Langdon wind project is five years. OTP has adjusted its Deferred Tax Assets and Deferred Tax Credits by $9.2 million for potential unused North Dakota wind tax credits related to the Langdon wind project.

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	2011	2010	2009
Balance on January 1	$900	$900	$284
Increases Related to Tax Positions for Prior Years	11,238	--	900
Uncertain Positions Resolved During Year	--	--	(284)
Balance on December 31	$12,138	$900	$900

The balance of unrecognized tax benefits as of December 31, 2011 would not reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2011 is not expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in our consolidated statement of income. Amounts accrued for interest on tax uncertainties as of December 31, 2011 was $0.7 million.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2011, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2006.

16. Asset Retirement Obligations (AROs)

The Company's AROs are related to OTP's coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

OTP recorded no new AROs in 2011.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2011 and 2010 are presented in the following table:

(in thousands)	2011	2010
Asset Retirement Obligations		
Beginning Balance	$4,402	$4,050
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	22	--
Accrued Accretion	384	352
Settlements	--	--
Ending Balance	$4,808	$4,402
Asset Retirement Costs Capitalized		
Beginning Balance	$1,497	$1,497
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Settlements	--	--
Ending Balance	$1,497	$1,497
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$290	$233
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	4	--
Accrued Depreciation	57	57
Settlements	--	--
Ending Balance	$351	$290
Settlements		
Original Capitalized Asset Retirement Cost - Retired	$--	$--
Accumulated Depreciation	--	--
Asset Retirement Obligation	$--	$--
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	$--	$--

17. Discontinued Operations

On May 6, 2011, the Company completed the sale of IPH for approximately $87.0 million in cash, including $3.0 million deposited in an Escrow account. In the second half of 2011, the IPH sales proceeds were reduced by $1.2 million related to a purchase price adjustment. On December 29, 2011 the Company completed the sale of Wylie, its trucking business, for approximately $25.0 million in cash. On January 18, 2012 the Company sold the assets of Aviva for $0.3 million in cash. Aviva was a wholly owned subsidiary of ShoreMaster that sells a variety of recreational equipment. On February 6, 2012 the Company entered into an agreement to sell DMS for $30.0 million in cash, with an expected closing date of February 29, 2012, subject to certain closing conditions. Based on the offering price for DMS, the Company recorded a pre-tax asset impairment charge of $56.4 million. The financial position, results of operations, and cash flows of IPH, Wylie, Aviva and DMS are reported as discontinued operations in the Company's consolidated financial statements as of December 31, 2011 and December 31, 2010, and for the years ended December 31, 2011, 2010 and 2009. Following are summary presentations of the results of discontinued operations for the years ended December 31, 2011, 2010 and 2009, along with the major components of assets and liabilities of discontinued operations as of December 31, 2011 and 2010:

	For the Year Ended December 31, 2011					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$28,125	$49,884	$2,206	$89,558	$ (4,119)	$165,654
Operating Expenses	24,046	55,927	3,976	85,244	(4,119)	165,074
Asset Impairment Charge	--	--	456	56,379		56,835
Operating Income (Loss)	4,079	(6,043)	(2,226)	(52,065)		(56,255)
Other Income (Deductions)	(228)	18	(18)	281	(3)	50
Interest Expense	11	709	379	1,726	(2,772)	53
Income Tax Expense (Benefit)	1,462	(2,683)	(1,050)	(16,058)	1,108	(17,221)
Net Income (Loss) from Operations	2,378	(4,051)	(1,573)	(37,452)	1,661	(39,037)
Gain (Loss) on Disposition Before Taxes	15,471	(946)	--	--		14,525
Income Tax Expense on Disposition	2,997	2,854	--	--		5,851
Net Gain (Loss) on Disposition	12,474	(3,800)	--	--		8,674
Net Income (Loss)	$14,852	$(7,851)	$(1,573)	$(37,452)	$ 1,661	$(30,363)

	For the Year Ended December 31, 2010					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$77,412	$54,143	$2,704	$100,301	$ (3,601)	$230,959
Operating Expenses	65,261	52,311	3,200	98,794	(3,601)	215,965
Asset Impairment Charge	--	--	489	--		489
Operating Income (Loss)	12,151	1,832	(985)	1,507		14,505
Other Income (Deductions)	(326)	8	(10)	331		3
Interest Expense	111	522	346	1,289	(2,176)	92
Income Tax Expense (Benefit)	3,716	511	(532)	369	870	4,934

Net Income (Loss)	$7,998	$807	$(809)	$180	$ 1,306	$9,482

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	For the Year Ended December 31, 2009					
(in thousands)	IPH	Wylie	Aviva	DMS	Intercompany Transactions Adjustment	Total
Operating Revenues	$79,098	$32,228	$2,992	$110,006	$ (3,504)	$220,820
Operating Expenses	66,847	36,476	4,031	113,066	(3,504)	216,916
Product Recall and Testing Costs	--	--	1,625	--		1,625
Operating Income (Loss)	12,251	(4,248)	(2,664)	(3,060)		2,279
Other Income (Deductions)	(398)	6	(7)	298		(101)
Interest Expense	36	282	190	449	(860)	97
Income Tax Expense (Benefit)	4,410	(1,814)	(1,137)	(1,114)	344	689
Net Income (Loss)	$7,407	$(2,710)	$(1,724)	$(2,097)	$ 516	$1,392

	December 31, 2011				
(in thousands)	IPH	Wylie	Aviva	DMS	Total
Current Assets	$--	$--	$912	$28,408	$29,320
Net Plant	--	--	--	372	372
Assets of Discontinued Operations	$--	$--	$912	$28,780	$29,692
Current Liabilities	$--	$--	$399	$14,341	$14,740
Deferred Income Taxes	--	--	(232)	(1,579)	(1,811)
Deferred Credits - Other	--	--	--	119	119
Long-Term Debt	--	--	--	715	715
Liabilities of Discontinued Operations	$--	$--	$167	$13,596	$13,763

	December 31, 2010				
(in thousands)	IPH	Wylie	Aviva	DMS	Total
Current Assets	$ 24,836	$ 17,701	$ 2,756	$ 26,843	$ 72,136
Goodwill	24,324	6,671	--	23,665	54,660
Other Intangibles - Net	10,852	--	--	39	10,891
Net Plant	30,672	3,505	54	25,351	59,582
Assets of Discontinued Operations	$ 90,684	$ 27,877	$ 2,810	$ 75,898	$ 197,269
Current Liabilities	$ 6,839	$ 6,605	$ 142	$ 15,936	$ 29,522
Other Noncurrent Liabilities	--	38	--	--	38
Deferred Income Taxes	11,553	2,772	(261)	4,262	18,326
Deferred Credits - Other	--	--	--	49	49
Long-Term Debt	634	80	--	1,056	1,770
Liabilities of Discontinued Operations	$ 19,026	$ 9,495	$ (119)	$ 21,303	$ 49,705

Quarterly Information (not audited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings (loss) per common share may not equal total earnings (loss) per common share. Amounts shown below will differ from amounts disclosed in previously filed quarterly reports on Forms 10-Q as a result of the dispositions of Wylie, Aviva and DMS, classified as discontinued operations in the fourth quarter of 2011. See note 17 to consolidated financial statements for more details.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2011	2010	2011	2010[2]	2011	2010	2011[3]	2010[4]
Operating Revenues[1]	$249,148	$210,133	$283,298	$216,909	$282,373	$225,033	$263,031	$240,116
Operating Income (Loss)[1]	15,556	15,898	13,413	(15,700)	18,006	10,186	5,314	13,690
Net Income (Loss):								
Continuing Operations	$5,213	$4,457	$5,125	$(16,650)	$7,336	$2,937	$(554)	$(1,570)
Discontinued Operations	483	260	13,703	2,432	(968)	3,164	(43,581)	3,626
	$5,696	$4,717	$18,828	$(14,218)	$6,368	$6,101	$(44,135)	$2,056
Earnings (Loss) Available for Common Shares:								
Continuing Operations	$5,029	$4,273	$4,941	$(16,833)	$7,152	$2,752	$(738)	$(1,753)
Discontinued Operations	483	260	13,381	2,336	(968)	3,162	(43,581)	3,626
	$5,512	$4,533	$18,322	$(14,497)	$6,184	$5,914	$(44,319)	$1,873
Basic Earnings (Loss) Per Share:								
Continuing Operations	$.14	$.12	$.14	$(.47)	$.20	$.08	$(.02)	$(.05)
Discontinued Operations	.01	.01	.37	.07	(.03)	.09	(1.21)	.10
	$.15	$.13	$.51	$(.40)	$.17	$.17	$(1.23)	$.05
Diluted Earnings (Loss) Per Share								
Continuing Operations	$.14	$.12	$.14	$(.47)	$.20	$.07	$(.02)	$(.05)
Discontinued Operations	.01	.01	.37	.07	(.03)	.09	(1.21)	.10
	$.15	$.13	$.51	$(.40)	$.17	$.16	$(1.23)	$.05
Dividends Declared Per Common Share	$.2975	$.2975	$.2975	$.2975	$.2975	$.2975	$.2975	$.2975
Price Range:								
High	23.43	25.39	23.48	23.10	22.07	21.19	22.28	23.33
Low	21.01	19.70	20.54	18.46	18.28	18.24	17.53	20.03
	35,877	35,721	35,926	35,799	35,933	35,806	35,953	35,808

Average Number of Common Shares Outstanding--Basic								
Average Number of Common Shares Outstanding--Diluted	36,081	35,940	36,164	35,799	36,172	36,076	35,953	35,808

1From continuing operations.

2 Results include a $19.7 million pre-tax asset impairment charge at ShoreMaster.

3Results include pre-tax asset impairment charges of $3.1 million at DMI and $0.5 million at OTESCO in continuing operations and $56.4 million at DMS and $0.5 million at Aviva in discontinued operations.

4Results include a $6.6 million increase in income tax expense at DMI's Canadian operations due to the establishment of a $5.5 million valuation allowance against deferred tax assets related to operating loss carryforwards and a $1.1 million reversal of deferred tax assets related to a reduction in statutory tax rates in Canada.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosures Controls and Procedures. Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2011, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2011.

Changes in Internal Control over Financial Reporting. There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report Regarding Internal Control Over Financial Reporting. Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this Annual Report on Form 10-K. The consolidated financial statements of the Company have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). These internal controls are designed only to provide reasonable assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition.

Management has completed its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework to conduct the required assessment of the effectiveness of the Company's internal control over financial reporting. Based on this assessment, management concluded that, as of December 31, 2011, the Company's internal control over financial reporting was effective based on those criteria. The Company's independent registered public accounting firm, Deloitte & Touche LLP, has audited the Company's consolidated financial statements included in this Annual Report on Form 10-K and issued an attestation report on the Company's internal control over financial reporting.

Attestation Report of Independent Registered Public Accounting Firm. The attestation report of Deloitte & Touche LLP, the Company's independent registered public accounting firm, regarding the Company's internal control over financial reporting is provided on Page 66.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under "Election of Directors" in the Company's definitive Proxy Statement for the 2012 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A hereto. The information regarding Section 16 reporting is incorporated by reference to the information under "Security Ownership of Directors and Officers - Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's definitive Proxy Statement for the 2012 Annual Meeting. The information required by this Item regarding the Company's procedures for recommending nominees to the Board of Directors is incorporated by reference to the information under "Meetings and Committees of the Board of Directors – Corporate Governance Committee" in the Company's definitive Proxy Statement for the 2012 Annual Meeting. The information required by this Item in regards to the Audit Committee is incorporated by reference to the information under "Meetings and Committees of the Board of Directors – Audit Committee" in the Company's definitive Proxy Statement for the 2012 Annual Meeting. The information regarding the Company's Audit Committee financial experts is incorporated by reference to the information under "Meetings and Committees of the Board – Audit Committee" in the Company's definitive Proxy Statement for the 2012 Annual Meeting.

The Company has adopted a code of conduct that applies to all of its directors, officers (including its principal executive officer, principal financial officer, and its principal accounting officer or controller or person performing similar functions) and employees. The Company's code of conduct is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of conduct by posting such information on its website at the address specified above. Information on the Company's website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

Item 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under "Compensation Discussion and Analysis," "Report of Compensation Committee," "Executive Compensation" and "Director Compensation" in the Company's definitive Proxy Statement for the 2012 Annual Meeting.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item regarding security ownership is incorporated by reference to the information under "Outstanding Voting Shares" and "Security Ownership of Directors and Officers" and "Proposal to Amend the 1999 Employee Stock Purchase Plan—Equity Compensation Plan Information" in the Company's definitive Proxy Statement for the 2012 Annual Meeting.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information under "Policy and Procedures Regarding Transactions with Related Persons," "Election of Directors" and "Meetings and Committees of the Board of Directors" in the Company's definitive Proxy Statement for the 2012 Annual Meeting.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under “Ratification of Independent Registered Public Accounting Firm - Fees” and “Ratification of Independent Registered Public Accounting Firm – Pre-Approval of Audit/Non-Audit Services Policy” in the Company’s definitive Proxy Statement for the 2012 Annual Meeting.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of documents filed as part of this report:

1. Financial Statements

2. Financial Statement Schedules

Schedules are omitted because of the absence of the conditions under which they are required, because the amounts are insignificant or because the information required is included in the financial statements or the notes thereto.

3. Exhibits

The following Exhibits are filed as part of, or incorporated by reference into, this report.

	File No.	Previously Filed As Exhibit No.	
2-A	8-K filed 7/1/09	2.1	—Plan of Merger, dated as of June 30, 2009, by and among Otter Tail Corporation (now known as Otter Tail Power Company), Otter Tail Holding Company (now known as Otter Tail Corporation) and Otter Tail Merger Sub Inc.
3-A	8-K filed 7/1/09	3.1	—Restated Articles of Incorporation.
3-B	8-K filed 7/1/09	3.2	—Restated Bylaws.
4-A	8-K filed 2/28/07	4.1	—Note Purchase Agreement, dated as of February 23, 2007, between the Company and Cascade Investment L.L.C.
4-A-1	8-K filed 7/1/09	4.3	—Amendment No. 2, dated as of June 30, 2009, to Note Purchase Agreement, dated as of February 23, 2007.
4-A-2	8-K filed 6/29/10	4.2	—Amendment No. 3, dated as of June 23, 2010, to Note Purchase Agreement, dated as of February 23, 2007.
4-A-3	8-K filed 8/3/10	4.1	—Amendment No. 4, dated as of July 24, 2010, to Note Purchase Agreement, dated as of February 23, 2007.

4-A-4	8-K filed 12/13/11	4.1	—Amendment No. 5, dated as of December 12, 2011, to Note Purchase Agreement, dated as of February 23, 2007.
4-B	8-K filed 8/23/07	4.1	—Note Purchase Agreement, dated as of August 20, 2007.
4-B-1	8-K filed 12/20/07	4.3	—First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007.
4-B-2	8-K filed 9/15/08	4.1	—Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007.
4-B-3	8-K filed 7/1/09	4.2	—Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007.

	File No.	Previously Filed As Exhibit No.	
4-C	8-K filed 5/10/10	4.1	—Second Amended and Restated Credit Agreement, dated as of May 4, 2010, between Otter Tail Corporation and the Banks named therein, U.S. Bank National Association, a national banking association, as administrative agent for the Banks and as Lead Arranger, Bank of America, N.A. and JPMorgan Chase Bank, National Association, as Co-Syndication Agents, and KeyBank National Association, as Documentation Agent.
4-C-1			—First Amendment, dated as of December 15, 2011, to Second Amended and Restated Credit Agreement, dated as of May 4, 2010.
4-D	8-K filed 3/8/11	4.1	—Amended and Restated Credit Agreement, dated as of March 3, 2011, among Otter Tail Power Company and the Banks named therein, JPMorgan Chase Bank, N.A., and Bank of America, N.A., as Syndication Agents, KeyBank National Association and CoBank, ACB, as Documentation Agents, and U.S. Bank National Association as administrative agent for the Banks.
4-E	8-K filed 8/3/11	4.1	—Note Purchase Agreement, dated as of July 29, 2011, between Otter Tail Power Company and the Purchasers named therein.
4-F	8-K filed 11/18/97	4-D-11	—Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 between the registrant and U.S. Bank National Association (formerly First Trust National Association), as Trustee.
4-G-1	8-K filed 7/1/09	4.1	—First Supplemental Indenture, dated as of July 1, 2009, to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997.
4-G-2	8-K filed 12/4/09	4.1	—Officer’s Certificate and Authentication Order, dated December 4, 2009, for the 9.000% Notes due 2016 (which includes the form of Note) issued pursuant to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 and the First Supplemental Indenture thereto, dated as of July 1, 2009.
10-A	2-39794	4-C	—Integrated Transmission Agreement, dated August 25, 1967, between Cooperative Power Association and the Company.
10-A-1	10-K for year ended 12/31/92	10-A-1	—Amendment No. 1, dated as of September 6, 1979, to Integrated Transmission Agreement, dated as of August 25, 1967, between Cooperative Power Association and the Company.
10-A-2	10-K for year ended 12/31/92	10-A-2	—Amendment No. 2, dated as of November 19, 1986, to Integrated Transmission Agreement between Cooperative Power Association and the Company.
10-C-1	2-55813	5-E	—Contract dated July 1, 1958, between Central Power Electric Corporation, Inc., and the Company.

10-C-2	2-55813	5-E-1	—Supplement Seven dated November 21, 1973. (Supplements Nos. One through Six have been superseded and are no longer in effect.)
10-C-3	2-55813	5-E-2	—Amendment No. 1 dated December 19, 1973, to Supplement Seven.
10-C-4	10-K for year ended 12/31/91	10-C-4	—Amendment No. 2 dated June 17, 1986, to Supplement Seven.
10-C-5	10-K for year ended 12/31/92	10-C-5	—Amendment No. 3 dated June 18, 1992, to Supplement Seven.
10-C-6	10-K for year ended 12/31/93	10-C-6	—Amendment No. 4 dated January 18, 1994 to Supplement Seven.
10-D	2-55813	5-F	—Contract dated April 12, 1973, between the Bureau of Reclamation and the Company.

	File No.	Previously Filed As Exhibit No.	
10-E-1	2-55813	5-G	—Contract dated January 8, 1973, between East River Electric Power Cooperative and the Company.
10-E-2	2-62815	5-E-1	—Supplement One dated February 20, 1978.
10-E-3	10-K for year ended 12/31/89	10-E-3	—Supplement Two dated June 10, 1983.
10-E-4	10-K for year ended 12/31/90	10-E-4	—Supplement Three dated June 6, 1985.
10-E-5	10-K for year ended 12/31/92	10-E-5	—Supplement No. Four, dated as of September 10, 1986.
10-E-6	10-K for year ended 12/31/92	10-E-6	—Supplement No. Five, dated as of January 7, 1993.
10-E-7	10-K for year ended 12/31/93	10-E-7	—Supplement No. Six, dated as of December 2, 1993.
10-F	10-K for year ended 12/31/89	10-F	—Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970).
10-F-1	10-K for year ended 12/31/89	10-F-1	—Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-F-2	10-K for year ended 12/31/91	10-F-2	—Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-F-3	10-K for year ended 12/31/91	10-F-3	—Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-F-4	10-K for year ended 12/31/91	10-F-4	—Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-F-5	10-Q for quarter ended 9/30/03	10.1	—Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-F-6	10-K for year ended 12/31/92	10-F-5	—Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-G	10-Q for quarter ended 06/30/04	10.3	—Master Coal Purchase and Sale Agreement by and between the Company, Montana-Dakota Utilities Co., Northwestern Corporation and Kennecott Coal Sales Company-Big Stone Plant (dated as of June 1, 2004).
10-H	2-61043	5-H	

			—Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company and Minnesota Power & Light Company (dated as of July 1, 1977).
10-H-1	10-K for year ended 12/31/89	10-H-1	—Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-2	10-K for year ended 12/31/89	10-H-2	—Supplemental Agreement No. Two, dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement.
10-H-3	10-K for year ended 12/31/89	10-H-3	—Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-4	10-K for year ended 12/31/92	10-H-4	—Agreement, dated as of September 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No. 1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978.

	File No.	Previously Filed As Exhibit No.	
10-H-5	10-Q for quarter ended 9/30/01	10-A	—Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-6	10-Q for quarter ended 9/30/03	10.2	—Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-I	2-63744	5-I	—Coyote Plant Coal Agreement by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company, Minnesota Power & Light Company, and Knife River Coal Mining Company (dated as of January 1, 1978).
10-I-1	10-K for year ended 12/31/92	10-I-1	—Addendum, dated as of March 10, 1980, to Coyote Plant Coal Agreement.
10-I-2	10-K for year ended 12/31/92	10-I-2	—Amendment (No. 3), dated as of May 28, 1980, to Coyote Plant Coal Agreement.
10-I-3	10-K for year ended 12/31/92	10-I-3	—Fourth Amendment, dated as of August 19, 1985, to Coyote Plant Coal Agreement.
10-I-4	10-Q for quarter ended 6/30/93	19-A	—Sixth Amendment, dated as of February 17, 1993, to Coyote Plant Coal Agreement.
10-I-5	10-K for year ended 12/31/01	10-I-5	—Agreement and Consent to Assignment of the Coyote Plant Coal Agreement.
10-J-1	10-Q for quarter ended 9/30/99	10	—Power Sales Agreement between the Company and Manitoba Hydro Electric Board (dated as of July 1, 1999).
10-K	10-K for year ended 12/31/91	10-L	—Integrated Transmission Agreement by and between the Company, Missouri Basin Municipal Power Agency and Western Minnesota Municipal Power Agency (dated as of March 31, 1986).
10-K-1	10-K for year ended 12/31/88	10-L-1	—Amendment No. 1, dated as of December 28, 1988, to Integrated Transmission Agreement (dated as of March 31, 1986).
10-L	10-Q for quarter ended 06/30/04	10.1	—Master Coal Purchase Agreement by and between the Company and Kennecott Coal Sales Company - Hoot Lake Plant (dated as of December 31, 2001).
10-M	8-K filed 7/1/09	10.1	—Standstill Agreement, dated July 1, 2009, by and between the Registrant and Cascade Investment, L.L.C.
10-M-1	8-K filed 1/9/12	10.1	—Letter Agreement dated January 5, 2012 terminating the Standstill Agreement, dated July 1, 2009, between Otter Tail Corporation and Cascade Investment, L.L.C.

10-N-1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended.*
10-N-1a	10-K for year ended 12/31/10	10-N-1A	—First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10-N-2	8-K filed 02/04/05	10.1	—Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-2a	10-K for year ended 12/31/06	10-N-2A	—First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-2b	10-K for year ended 12/31/10	10-N-2B	—Second Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-3	10-K for year ended 12/31/93	10-N-5	—Nonqualified Profit Sharing Plan.*
10-N-4	10-Q for quarter ended 3/31/02	10-B	—Nonqualified Retirement Savings Plan, as amended.*

	File No.	Previously Filed As Exhibit No.	
10-N-5	10-Q for quarter ended 9/30/11	10.1	—Nonqualified Retirement Plan (2011 Restatement).*
10-N-6	8-K filed 4/13/06	10.3	—1999 Employee Stock Purchase Plan, As Amended (2006).
10-N-7	8-K filed 4/13/06	10.4	—1999 Stock Incentive Plan, As Amended (2006).
10-N-8	10-K for year ended 12/31/05	10-N-7	—Form of Stock Option Agreement.*
10-N-9	10-K for year ended 12/31/05	10-N-8	—Form of Restricted Stock Agreement.*
10-N-10	8-K filed 4/13/06	10.2	—Form of Performance Award Agreement.*
10-N-11			—Executive Annual Incentive Plan.*
10-N-12	10-Q for quarter ended 6/30/06	10.5	—Form of Restricted Stock Unit Award Agreement.*
10-N-13	8-K filed 4/13/06	10.1	—Form of Restricted Stock Award Agreement for Directors.
10-O	8-K filed 3/17/10	1.1	—Distribution Agreement, dated March 17, 2010, between Otter Tail Corporation and J.P. Morgan Securities Inc.
10-P-1	10-K for year ended 12/31/10	10-P-1	—Executive Employment Agreement, John Erickson.*
10-P-2	10-K for year ended 12/31/10	10-P-3	—Executive Employment Agreement, Kevin Moug.*
10-P-3	10-K for year ended 12/31/10	10-P-4	—Executive Employment Agreement, George Koeck.*
10-P-4	10-K for year ended 12/31/10	10-P-5	—Executive Employment Agreement, Michelle Kommer.*
10-P-5			—Executive Employment Agreement, Chuck MacFarlane.*
10-P-6			—Executive Employment Agreement, Shane Waslaski.*
10-Q-1	10-K for year ended 12/31/10	10-Q-1	—Change in Control Severance Agreement, John D. Erickson.*

10-Q-2	10-K for year ended 12/31/10	10-Q-3	—Change in Control Severance Agreement, Kevin G. Moug.*
10-Q-3	10-K for year ended 12/31/10	10-Q-4	—Change in Control Severance Agreement, George Koeck.*
10-Q-4	10-K for year ended 12/31/10	10-Q-5	—Change in Control Severance Agreement, Michelle L. Kommer.*
10-Q-5			—Change in Control Severance Agreement, Chuck MacFarlane.*
10-Q-6			—Change in Control Severance Agreement, Shane Waslaski.*
10-Q-7			—Change in Control Severance Agreement, Edward J. McIntyre.*
12.1			—Calculation of Ratios of Earnings to Fixed Charges and Preferred Dividends.
21-A			—Subsidiaries of Registrant.
23-A			—Consent of Deloitte & Touche LLP.
24-A			—Powers of Attorney.
31.1			—Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

	File No.	Previously Filed As Exhibit No.	
31.2			—Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			—Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2			—Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS			—XBRL Instance Document
101.SCH			—XBRL Taxonomy Extension Schema Document
101.CAL			—XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB			—XBRL Taxonomy Extension Label Linkbase Document
101.PRE			—XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF			—XBRL Taxonomy Extension Definition Linkbase Document

*Management contract of compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OTTER TAIL CORPORATION

By	/s/ Kevin G. Moug Kevin G. Moug Chief Financial Officer and Senior Vice President
Dated:	February 29, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature and Title

Edward J. McIntyre Chief Executive Officer and President (principal executive officer) and Director	)	
Kevin G. Moug Chief Financial Officer and Senior Vice President (principal financial and accounting officer)	)	
Nathan I. Partain Chairman of the Board and Director	)	By /s/ Edward J. McIntyre Edward J. McIntyre Pro Se and Attorney-in-Fact Dated February 29, 2012
Karen M. Bohn, Director	)	
John D. Erickson, Director	)	
Arvid R. Liebe, Director	)	
Joyce Nelson Schuette, Director	)	
Mark W. Olson, Director	)	
Gary J. Spies, Director	)	
James B. Stake, Director	)	

EXHIBIT INDEX

Exhibit Number	Description
4-C-1	First Amendment, dated as of December 15, 2011, to Second Amended and Restated Credit Agreement, dated as of May 4, 2010.
10-N-11	Executive Annual Incentive Plan
10-P-5	Executive Employment Agreement, Chuck MacFarlane
10-P-6	Executive Employment Agreement, Shane Waslaski
10-Q-5	Change in Control Severance Agreement, Chuck MacFarlane
10-Q-6	Change in Control Severance Agreement, Shane Waslaski
10-Q-7	Change in Control Severance Agreement, Edward J. McIntyre
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