Otter Tail Corp
Form 10-K
February 27, 2013

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

FORM 10-K

(Mark One)

x Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2012

o 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 o)

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). (Yes o No x)

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 29, 2012 was $777,976,655.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 36,169,488 Common Shares ($5 par value) as of February 15, 2013.

Documents Incorporated by Reference:

Proxy Statement for the 2013 Annual Meeting-Portions incorporated by reference into Part III

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Definitions

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

ADP	Advance Determination of Prudence
Aevenia	Aevenia, Inc.
AFUDC	Allowance for Funds Used During Construction
AQCS	Air Quality Control System
ARO	Accumulated Asset Retirement Obligation
ASC	Accounting Standards Codification
ASM	Ancillary Services Market
Aviva	Aviva Sports, Inc.
BACT	Best-Available Control Technology
BART	Best-Available Retrofit Technology
Bemidji Project	Bemidji-Grand Rapids 230 kV Project
Brookings Project	Brookings-Southeast Twin Cities 345 kV Project
BTD	BTD Manufacturing, Inc.
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CapX2020	Capacity Expansion 2020
Cascade	Cascade Investment LLC
CCMC	Coyote Creek Mining Company, L.L.C.
CCRA	Conservation Cost Recovery Adjustment
CO2	Carbon Dioxide
CON	Certificate of Need
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction Work in Progress
DENR	Department of Environment and Natural Resources
DMI	DMI Industries, Inc.
DMS	DMS Health Technologies, Inc.
ECRR	Environmental Cost Recovery Rider
EEI	Edison Electric Institute Index
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESSRP	Executive Survivor and Supplemental Retirement Plan
Fargo Project	Fargo-Monticello 345 kV Project
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Foley	Foley Company
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
IPH	Idaho Pacific Holdings, Inc.
IRP	Integrated Resource Plan
JPMS	J.P. Morgan Securities
kV	kiloVolt
kW	kiloWatt
kwh	kilowatt-hour
LSA	Lignite Sales Agreement

MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards
MDU	MDU Resources Group, Inc.
MEI	Moorhead Electric, Inc.
MISO	Midwest Independent Transmission System Operator
MNCIP	Minnesota Conservation Improvement Program
MNDOC	Minnesota Department of Commerce
MNOAG	Minnesota Office of Attorney General
MNRRA	Minnesota Renewable Resource Adjustment
MPCA	Minnesota Pollution Control Agency

MPUC	Minnesota Public Utilities Commission
MRO	Midwest Reliability Organization
MVP	Multi-Value Project
MW	Megawatt
NAEMA	North American Energy Marketers Association
NDDOH	North Dakota Department of Health
NDPSC	North Dakota Public Service Commission
NDRRA	North Dakota Renewable Resource Cost Recovery Rider Adjustment
NICF	Notice of Interest to Construct Facilities
NPCA	National Parks Conservation Association
Northern Pipe	Northern Pipe Products, Inc.
NOx	Nitrogen Oxide
NSPS	New Source Performance Standards
OTESCO	Otter Tail Energy Services Company
OTP	Otter Tail Power Company
PACE	Partnership in Assisting Community Expansion
PCOR	Plains CO2 Reduction Partnership
PEM	Power and Energy Market
PM2.5	Particulate Matter Less Than 2.5 Microns
PS	Polystyrene
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PVC	Polyvinyl Chloride
RCRA	Resource Conservation and Recovery Act
SCR	Selective Catalytic Reduction
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
SF6	Sulfur Hexaflouride
ShoreMaster	ShoreMaster, Inc.
SIP	State Implementation Plan
SO2	Sulfur Dioxide
T.O. Plastics	T.O. Plastics, Inc.
Tariff	Energy and Operating Reserve Markets Tariff
TCR	Transmission Cost Recovery
Trinity	Trinity Industries, Inc.
VaR	Value at Risk
Varistar	Varistar Corporation
VIE	Variable Interest Entity
Vinyltech	Vinyltech Corporation
Wylie	E.W. Wylie Corporation

PART I

Item 1. BUSINESS

(a) General Development of Business

Otter Tail Power Company was incorporated in 1907 under the laws of the State of Minnesota. In 2001, the name was changed to “Otter Tail Corporation” to more accurately represent the broader scope of electric and nonelectric operations and the name Otter Tail Power Company (OTP) was retained for use by the electric utility. On July 1, 2009, Otter Tail Corporation completed a holding company reorganization whereby OTP, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (the Company). The new parent holding company was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization. The Company’s executive offices are located at 215 South Cascade Street, P.O. Box 496, Fergus Falls, Minnesota 56538-0496 and 4334 18th Avenue SW, Suite 200, P.O. Box 9156, Fargo, North Dakota 58106-9156. The Company’s telephone number is (866) 410-8780.

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

Otter Tail Corporation and its subsidiaries conduct business primarily in the United States. The Company had approximately 2,286 full-time employees in its continuing operations at December 31, 2012.

In 2011 and 2012, the Company sold several businesses in execution of its announced strategy of realigning its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations. In 2011, the Company sold Idaho Pacific Holdings, Inc. (IPH), its Food Ingredient Processing business, and E.W. Wylie Corporation (Wylie), its trucking company, which was included in its former Wind Energy segment. In January 2012, the Company sold the assets of Aviva Sports, Inc. (Aviva), a recreational equipment manufacturer and a wholly owned subsidiary of ShoreMaster, Inc. (ShoreMaster), the Company’s waterfront equipment manufacturer. In February 2012, the Company sold DMS Health Technologies, Inc. (DMS), its former Health Services segment business. In November 2012, the Company completed the sale of the assets of DMI Industries, Inc. (DMI), its manufacturer of towers for wind turbines, and exited the wind tower manufacturing business. In December 2012, the Company entered into negotiations to sell the assets of ShoreMaster and completed the sale on February 8, 2013. The Company’s business structure now consists of the following segments: Electric, Manufacturing, Construction and Plastics.

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.

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

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

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. The Company has lowered its overall risk by investing in rate base growth opportunities in its Electric segment and divesting certain non-electric operating companies that no longer fit the Company's portfolio criteria. This strategy is intended to create a more predictable earnings stream, improve the Company's credit quality and preserve its ability to fund the dividend. The Company's goal is to deliver annual growth in earnings per share between four to seven percent over the next several years. The growth is expected to come from the substantial increase in the Company's regulated utility rate base and from planned increased earnings from existing capacity already in place at the Company's manufacturing and infrastructure businesses. The Company will also evaluate opportunities to allocate capital to potential acquisitions in its Manufacturing segment. Over time, the Company expects the electric utility business will provide approximately 75% to 85% of its overall earnings. The Company expects its Manufacturing and Infrastructure businesses will provide 15% to 25% of its earnings, and will continue to be a fundamental part of its strategy.

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

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

a strategic differentiation from competitors and a sustainable cost advantage,

a stable or growing industry,

an ability to quickly adapt to changing economic cycles, and

a strong management team committed to operational excellence.

For a discussion of the Company's results of operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations," on pages 38 through 60 of this Annual Report on Form 10-K.

(b) Financial Information about Industry Segments

The Company is engaged in businesses classified into four segments: Electric, Manufacturing, Construction and Plastics. Financial information about the Company's segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 80 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 service area with outer boundaries that encompass a total expanse of 70,000 square miles of western Minnesota, eastern North Dakota, and northeastern South Dakota. OTESCO, headquartered in Fergus Falls, Minnesota, provides technical and engineering services primarily in North Dakota and Minnesota. The Company derived 41%, 41% and 48% of its consolidated operating revenues from the Electric segment for each of the three years ended December 31, 2012, 2011 and 2010, respectively.

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

State	2012	2011
Minnesota	48.9 %	48.8 %
North Dakota	42.0	42.2
South Dakota	9.1	9.0
Total	100.0 %	100.0 %

The territory served by OTP is predominantly agricultural. The aggregate population of OTP's retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 125,646 people live in communities having a population of more than 1,000, according to the 2010 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,427); Bemidji, Minnesota (13,431); and Fergus Falls, Minnesota (13,138). As of December 31, 2012, OTP served 129,786 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	2012	2011
Commercial	36.0 %	36.2 %
Residential	32.6	32.9
Industrial	25.0	23.8
All Other Sources	6.4	7.1
Total	100.0 %	100.0 %

Wholesale electric energy kilowatt-hour (kwh) sales were 11.8% of total kwh sales for 2012 and 12.9% for 2011. Wholesale electric energy kwh sales decreased by 10.8% between the years while revenue per kwh sold decreased by 14.5%. 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, 2012 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants

Big Stone Plant	256,600	kW
Coyote Station	149,100	
Hoot Lake Plant	141,600	
Total Baseload Net Plant	547,300	kW
Combustion Turbine and Small Diesel Units	108,000	kW
Hydroelectric Facilities	2,800	kW
Owned Wind Facilities (rated at nameplate)		
Luverne Wind Farm (33 turbines)	49,500	kW
Ashtabula Wind Center (32 turbines)	48,000	
Langdon Wind Center (27 turbines)	40,500	
Total Owned Wind Facilities	138,000	kW

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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 2012, OTP generated about 68.3% 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, 2012:

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 Company1	50,000 kW
Great River Energy2	50,000
Total Purchased Power	100,000 kW

1Expires May 2013.
2Increases to 100,000 kW from June 2013 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 2012. The MISO Resource Adequacy Construct is significantly changed for the 2013/2014 MISO Planning Year. These changes will be effective beginning June 1, 2013. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2013 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 2012 and 2011:

	2012		2011	
Sources	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated
Subbituminous Coal	2,094,293	61.2 %	2,125,170	56.7 %
Lignite Coal	782,358	22.9	1,062,153	28.3
Wind and Hydro	490,387	14.3	527,913	14.1
Natural Gas and Oil	55,637	1.6	33,367	0.9

Total	3,422,675	100.0 %	3,748,603	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, 2016
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	May 4, 2016
Coyote Station	Coyote Creek Mining Company, L.L.C.	North Dakota lignite	December 31, 2040
Hoot Lake Plant	Cloud Peak Energy Resources LLC	Montana subbituminous	December 31, 2014

OTP has about 42% of its coal needs for Big Stone under contract through December 2016.

The contract with Dakota Westmoreland Corporation expires on May 4, 2016. In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton to be paid by the Coyote Station owners under the LSA will reflect the cost of production, along with an agreed profit and capital charge. The LSA provides for the Coyote Station owners to purchase the membership interests in CCMC in the event of certain early termination events and also at the end of the term of the LSA.

OTP has about 78% of its coal needs for Hoot Lake Plant under contract through December 2014.

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 2012, 2011, and 2010 was $2.108, $1.922, and $1.813, 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:

		2012		2011	
Rates	Regulation	% of Electric Revenues	% of kwh Sales	% of Electric Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	45.2 %	43.4 %	45.1 %	42.2 %
ND Retail Sales	ND Public Service Commission	38.8	36.4	39.1	36.5
SD Retail Sales	SD Public Utilities Commission	8.4	8.5	8.3	8.4
Transmission & Wholesale	Federal Energy Regulatory Commission	7.6	11.7	7.5	12.9
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 also has approved tariffs in its three service territories which allow qualifying customers to release and sell energy back to OTP when wholesale energy prices make such transactions desirable.

With a few minor exceptions, OTP's electric retail rate schedules provide for adjustments in rates based on the cost of fuel delivered to OTP's generating plants, as well as for adjustments based on the cost of electric energy purchased by OTP. OTP also credits certain margins from wholesale sales to the fuel and purchased power adjustment. The adjustments for fuel and purchased power costs are presently based on a two month moving average in Minnesota and by the Federal Energy Regulatory Commission (FERC), a three month moving average in South Dakota and a four month moving average in North Dakota. These adjustments are applied to the next billing period after becoming applicable. These adjustments also include an over or under recovery mechanism, which is calculated on an annual basis in Minnesota and on a monthly basis in North Dakota and South Dakota.

The following summarizes the material regulations of each jurisdiction applicable to OTP's electric operations, as well as any specific electric rate proceedings during the last three years with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC. The Company's manufacturing and infrastructure businesses are not subject to direct regulation by any of these agencies.

Minnesota

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

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

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

2010 General Rate Case 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, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment. Final rates went into effect October 1, 2011. The overall increase to customers was approximately 1.6% compared to the authorized interim rate increase of 3.8%, which resulted in an interim rate refund to Minnesota retail electric customers of approximately $3.9 million in the fourth quarter of 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%. OTP's authorized rates of return are based on a capital structure of 48.28% long term debt and 51.72% common equity.

Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. The Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal.

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

A written order was issued by the MPUC on January 11, 2012 approving the recovery of $3.5 million in 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment (CCRA) increased from 3.0% to 3.8% for all Minnesota retail electric customers.

OTP recognized $2.2 million in MNCIP financial incentives in 2011 relating to 2011 program results. On March 30, 2012 OTP submitted its annual 2011 financial incentive filing request for $2.6 million and recognized an additional $0.4 million of incentive related to 2011 in 2012. In December 2012, the MPUC approved the recovery of $2.6 million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer's bill to an amount per kwh consumed. The written order was issued on December 10, 2012. On January 1, 2013 OTP's MNCIP surcharge decreased from 3.8% of a customer's bill to $0.00142 per kwh, which equates to approximately 1.9% of a customer's bill. The per-kwh cost allocation method is the principle method approved by the MPUC for other electric utilities in Minnesota. OTP recognized $2.6 million of MNCIP financial incentives in 2012 relating to 2012 program results.

OTP had a regulatory asset of $6.1 million for allowable costs and financial incentives eligible for recovery through the MNCIP rider that had not been billed to Minnesota customers as of December 31, 2012.

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.

In a January 31, 2013 hearing, the MPUC approved OTP's recommendation that Hoot Lake Plant add pollution-control equipment at a cost of approximately $10.0 million to comply with EPA mercury and air toxics standards by 2015 and discontinue burning coal in 2020.

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 commencing in 2012. 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's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

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

The MPUC issued an order on January 12, 2010 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. The 2010 MNRRA was in place from September 1, 2010 through September 30, 2011 with a recovery of $17.0 million.

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 the MNRRA regulatory asset. OTP had a regulatory asset of $0.9 million for amounts eligible for recovery through the MNRRA rider that had not been billed to Minnesota customers as of December 31, 2012. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. The filing, which is still under review included a request to extend the period of the new rate for 18 months, which would reduce the current balance of unrecovered costs to zero. However, it is now estimated the remaining unrecovered costs will be collected by the end of May 2013, so OTP is planning to make a supplemental filing to request that the current rate be retained until the remaining balance is recovered and that the MNRRA then be suspended.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a CON proceeding, certified by the

MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

OTP requested recovery of its transmission investments being recovered through its Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs currently being recovered through OTP's Minnesota TCR rider to recovery in base rates. Final rates went into effect on October 1, 2011. OTP 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. The update to OTP's Minnesota TCR rider, approved by the MPUC on March 26, 2012, went into effect April 1, 2012.

In this TCR rider update, the MNPUC addressed how to handle utility investments in transmission facilities that qualify for regional cost allocation under the MISO tariff. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from the other MISO utilities. On March 26, 2012 the MPUC approved an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made with an offsetting credit for revenues received from other MISO utilities under the MISO tariff.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of 12 additional transmission related projects in subsequent Minnesota TCR rider filings. On August 22, 2012 the MNDOC filed comments and on August 24, 2012 the Minnesota Office of the Attorney General (MNOAG) filed comments. OTP filed reply comments on September 25, 2012 and supplemental comments on January 8, 2013 describing an agreement reached between OTP, the MNDOC and the MNOAG, to find eligible 3 of the 12 projects. MPUC approval of that agreement is pending. If approval is obtained to include additional projects in the rider, investment in the approved projects will be included in the next annual Minnesota TCR rider rate update filings, and recovery of the investment will begin through the TCR rider rates if subsequently approved by the MPUC. Updated costs associated with existing projects within the Minnesota TCR rider will also be included in the next annual rider rate update filing. OTP had a regulatory liability of $0.5 million as of December 31, 2012 for amounts billed to Minnesota customers that are subject to refund through the Minnesota TCR rider.

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

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, 2012, OTP had a regulatory asset of $2.1 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.

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, and on December 20, 2011 the MPUC granted OTP's petition. The MPUC's written order was issued on January 23, 2012.

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

The Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project. The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. Construction is underway for the remaining portions of the project with completion scheduled for the first quarter of 2015. OTP's share of the costs for the St. Cloud to Fargo portion of the Fargo Project is expected to be $84.2 million.

The Brookings Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Brookings Project. The MISO granted unconditional approval of the Brookings Project as a Multi-Value Project (MVP) under the MISO Open Access Transmission, Energy and Operating Reserves Market Tariff (Tariff) in December 2011. This project will be placed in 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 for the Brookings Project is expected to be $26.0 million.

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

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 2013. OTP is required to file its 2013 capital structure petition by May 14, 2013.

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 North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed. OTP 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 costs and returns on investments in renewable energy facilities under the NDRRA 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.

The 2010 NDRRA was in place for the period of September 1, 2010 through March 31, 2012 with a recovery of $15.6 million. On December 29, 2011 OTP submitted its annual update to the renewable rider with an April 1, 2012 effective date, which was approved by the NDPSC on March 21, 2012. The 2011 NDRRA has an expected recovery of $10.1 million over the period April 1, 2012 through March 31, 2013. OTP has a regulatory asset of $1.6 million for amounts eligible for recovery through the NDRRA rider that have not been billed to North Dakota customers as of December 31, 2012.

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 filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011, which was approved by the NDPSC on April 25, 2012, to go into effect May 1, 2012. On August 31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider, which the NDPSC approved on December 12, 2012 to go into effect January 1, 2013. OTP has a regulatory asset of $0.1 million for amounts eligible for recovery through the North Dakota TCR rider that have not been billed to North Dakota customers as of December 31, 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 the 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. As of December 31, 2012, OTP had a regulatory asset of $0.9 million of Big Stone II generation costs to be recovered.

The North Dakota's jurisdictional share of Big Stone II costs incurred by OTP related to transmission is $1.1 million. 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.

Big Stone Plant AQCS Request for ADP—An application for an ADP filed by OTP with the NDPSC on May 20, 2011 was approved on May 9, 2012.

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

CapX2020 - Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project. Completion of all phases of the Fargo Project is scheduled for the first quarter of 2015. OTP's share of the costs of the Fargo Project is expected to be $84.2 million.

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.

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 billed $570,000 to South Dakota customers under the TCR rider from December 1, 2011 through December 31, 2012 and had a regulatory asset of $2,000 for amounts eligible for recovery through the South Dakota TCR rider that had not been billed to South Dakota customers as of December 31, 2012. On September 4, 2012, OTP filed its annual update to the South Dakota TCR rider rate. The request is currently under review by the SDPUC.

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. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits from the original Big Stone II transmission owners to OTP.

Big Stone Plant AQCS—On March 30, 2012 OTP requested approval from the SDPUC for an Environmental Cost Recovery Rider (ECRR) to recover costs associated with the Big Stone Plant AQCS, with a proposed effective date of October 1, 2012. This rider is designed to recover the revenue requirements plus carrying charges of the Big Stone AQCS project while under construction as well as after completion of the project until placed into base rates through the filing of a rate case. For the initial period of October 1, 2012 through September 30, 2013, OTP is requesting revenue requirement recovery on expenditures incurred for the Big Stone Plant AQCS. The request is currently under review by the SDPUC.

CapX2020 Brookings–Southeast Twin Cities 345 kV Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of this project. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project will be placed in 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 of the Brookings Project is expected to be $26.0 million.

Energy Efficiency Plan—The SDPUC has encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use

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, or $84,000.

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 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 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 provides 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.

The Big Stone South – Brookings Project—OTP is jointly developing this project with Xcel Energy. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. A portion of this line is anticipated to use previously obtained Big Stone II transmission route permits and easements and is expected to be in service in 2017. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP. In December 2012 a request was filed with the SDPUC for recertification of a portion of the line route that was approved as part of the Big Stone II transmission development. OTP and Xcel Energy expect to make a joint route permit filing in the second quarter of 2013 for the remaining portion of the project.

The Ellendale – Big Stone South Project—OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU). OTP and MDU jointly filed an NICF with the SDPUC in March 2012. This project will require regulatory approval from both the SDPUC and the NDPSC. Route permits are expected to be filed with the respective commissions in the third quarter of 2013.

CapX2020 Brookings Project—In June 2011 the MISO board of directors granted conditional approval of the MVP cost allocation designation under the MISO Tariff for the Brookings Project, and the project was granted unconditional approval in December 2011 as an MVP.

NAEMA

OTP is a member of the North American Energy Marketers Association (NAEMA) which is an independent, non-profit trade association representing entities involved in the marketing of energy or in providing services to the energy industry. NAEMA has over 130 members with operations in 48 states and Canada. NAEMA was formed as a successor organization of the Power and Energy Market (PEM) of the Mid-Continent Area Power Pool (MAPP) in recognition that PEM had outgrown the MAPP region. Power pool sales are conducted continuously through NAEMA in accordance with schedules filed by NAEMA with the FERC.

MRO

OTP is a member of the Midwest Reliability Organization (MRO). The MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO began operations in 2005 and is one of eight regional entities in

North America operating under authority from regulators in the United States and Canada through a delegation agreement with the North American Electric Reliability Corporation. The MRO is responsible for: (1) developing and implementing reliability standards, (2) enforcing compliance with those standards, (3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity, and (4) providing an appeals and dispute resolution process.

The MRO region covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska and the majority of the territory in the states of South Dakota, Iowa and Wisconsin. The region includes more than 100 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, independent power producers and others who have interests in the reliability of the bulk power system. MRO assumed the reliability functions of the MAPP and Mid-America Interconnected Network, both former voluntary regional reliability councils.

MISO

OTP is a member of the MISO. As the transmission provider and security coordinator for the region, the MISO seeks to optimize the efficiency of the interconnected system, provide regional solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions. The MISO covers a broad region containing all or parts of 12 states and the Canadian province of Manitoba. The MISO has operational control of OTP’s transmission facilities above 100 kV, but OTP continues to own and maintain its transmission assets.

The MISO Energy Markets commenced operation on April 1, 2005. Through its Energy Markets, MISO seeks to develop options for energy supply, increase utilization of transmission assets, optimize the use of energy resources across a wider region and provide greater visibility of data. MISO aims to facilitate a more cost-effective and efficient use of the wholesale bulk electric system.

The MISO Ancillary Services Market (ASM) commenced on January 6, 2009. The 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, 2012 OTP invested approximately $23.5 million in environmental control facilities. The 2013 and 2014 construction budgets include approximately $89.5 million and $99.5 million, respectively, for environmental equipment for existing facilities.

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

The primary fuels burned by OTP's steam generating plants are North Dakota lignite coal and western subbituminous coal. Electrostatic precipitators have been installed at the principal units at the Hoot Lake Plant. Hoot Lake Plant Unit 1, which is the smallest of the three coal-fired units at Hoot Lake Plant, was retired as of December 31, 2005. As a result, OTP believes the units at the Hoot Lake Plant currently meet all presently applicable federal and state air quality and emission standards.

The South Dakota Department of Environment and Natural Resources 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 SO_2 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 SO_2 and nitrogen oxides (NO_x).

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

The national NO_x emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. All of OTP's generating facilities met the NO_x standards during 2012.

The EPA Administrator signed the Clean Air Interstate Rule (CAIR) on March 10, 2005. The EPA has concluded that SO_2 and NO_x are the chief emissions contributing to interstate transport of particulate matter less than 2.5 microns ($PM_{2.5}$). The EPA also concluded that NO_x emissions are the chief emissions contributing to ozone nonattainment.

Twenty-three states and the District of Columbia were found to contribute to ambient air quality $PM_{2.5}$ nonattainment in downwind states. On that basis, the EPA proposed to cap SO_2 and NO_x emissions in the designated states. Minnesota was included among the twenty-three states subject to emissions caps; North Dakota and South Dakota were not included. Twenty-five states were found to contribute to downwind 8-hour ozone nonattainment. None of the states in OTP's service territory were slated for NO_x reduction for 8-hour ozone nonattainment purposes. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAIR and the CAIR federal implementation plan in its entirety.

On December 23, 2008, the court reconsidered 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 was 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), on July 8, 2011. The final rule made several changes as compared to the proposed rule, including a substantial change in the allowance allocation methodology. A number of states and industry representatives challenged the rule, 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 Court issued an order on August 21, 2012 to vacate CSAPR. The order requires EPA to continue administering CAIR pending the promulgation of a valid replacement rule. Since CAIR is currently stayed for Minnesota, and does not apply to North or South Dakota, there is no impact to OTP at this time.

Air Quality – Hazardous Air Pollutants —On December 16, 2011 the EPA signed a final rule to reduce mercury and other air toxics emissions from power plants known as the Mercury and Air Toxics Standards (MATS) rule. The final rule became effective on April 16, 2012, and plants will have until April 16, 2015 to comply. However, the EPA is encouraging state permitting authorities to broadly grant a one-year compliance extension to plants that need additional time to install controls. The EPA is also providing a pathway for reliability critical units to obtain an additional year to achieve compliance; however, the EPA has indicated that it believes there will be few, if any situations, in which this pathway is needed. Based on OTP's review of the final rule, it appears that OTP's affected units would meet the requirements by installing the AQCS system at Big Stone, by adding fabric filters or upgrading the electrostatic precipitators on Hoot Lake Units 2 and 3, by installing mercury control technology such as activated carbon injection on all units, and by possibly installing dry sorbent injection at Hoot Lake Plant. Emissions monitoring equipment and/or stack testing will also be needed to verify compliance with the standards. Mercury emissions monitoring equipment was previously installed at Big Stone Plant and Coyote Station, but the equipment will need to be re-evaluated for operability under 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 —The EPA promulgated the Regional Haze Rule in 1999, and on June 15, 2005 the EPA provided final guidelines for conducting BART determinations under the rule. The Regional Haze Rule requires emissions reductions from BART-eligible sources that are deemed to contribute to visibility impairment in Class I air quality areas. Big Stone Plant is BART eligible, and the South Dakota Department of Environment and Natural Resources (DENR) determined that the plant is subject to emission reduction requirements based on the modeled contribution of the plant emissions to visibility impairment in downwind Class I air quality areas. 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). 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 Selective Catalytic Reduction (SCR) technology for NOx emission reduction in addition to the OTP-recommended separated over-fire air.

South Dakota developed and submitted its implementation plan and associated implementation rules to the EPA on January 21, 2011. The DENR and the EPA 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. EPA signed the final rule approving the South Dakota Regional Haze SIP and the Big Stone BART determination on March 29, 2012, and the final approval became effective on May 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. 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 and on December 20, 2011 the MPUC granted the petition. 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. The NDPSC held a special meeting on May 9, 2012 at which time the order was approved by all Commissioners. The order contains conditions for reporting and made no determination of the prudence of the technology for NOx control.

On March 30, 2012 OTP requested approval from the SDPUC for an ECRR to recover costs associated with the Big Stone Plant air quality control system. OTP is currently awaiting SDPUC action. This rider is designed to recover the revenue requirements plus carrying charges of the project while under construction as well as after completion of the project until placed into base rates through the filing of a rate case.

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 March 14, 2011 the North Dakota Department of Health (NDDOH) issued a construction permit to Coyote Station requiring installation of control equipment to limit its NOx emissions to 0.5 pounds per million Btu as calculated on a 30-day rolling average basis beginning on July 1, 2018. The current estimate of the total cost of the project is $6 million ($2.1 million for OTP's share). On March 1, 2012 EPA signed a final rule for partial approval of the North Dakota SIP that included the NOx emission rate permit conditions for Coyote Station as proposed by the NDDOH. The rule became effective on May 7, 2012.

In June 2012 the Sierra Club and National Parks Conservation Association (NPCA) filed an appeal of EPA's approval of the North Dakota Regional Haze SIP to the U.S. Eighth Circuit Court of Appeals. The petition for review was silent on the specific issues that the groups intended to challenge. On the same day Sierra Club/NPCA also separately filed a petition for reconsideration with the EPA. In the petition for reconsideration filed with EPA, Sierra Club/NPCA did not take issue with the Coyote Station NOx limit. However, in the Eighth Circuit appeal, Sierra Club/NPCA filed a brief on October 5, 2012 that included a challenge to EPA's determinations relative to Coyote Station. The groups are requesting the Eighth Circuit to reverse and remand EPA's SIP approval. An amicus brief was submitted to the Eighth Circuit on behalf of the Coyote Station on December 18, 2012.

Air Quality – Greenhouse Gas (GHG) Regulation —Combustion of fossil fuels for the generation of electricity is a major stationary source of CO_2 emissions in the United States and globally. OTP is an owner or part-owner of three baseload, coal-fired electricity generating plants and three fuel-oil or natural gas-fired combustion turbine peaking plants with a combined net dependable capacity of 652 MW. In 2012 these plants emitted approximately 3.5 million tons of CO_2.

OTP monitors and evaluates the possible adoption of national, regional, or state climate change and GHG legislation or regulations that would affect electric utilities. Congress previously considered but has not adopted GHG legislation which would require a reduction in GHG emissions, and there is no legislation under active consideration at this time. The likelihood of any federal mandatory CO_2 emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, is uncertain.

In April 2007, however, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate 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.

As of July 2011, sources emitting more than 100,000 tons per year of "CO2e", a measure that converts emissions of each GHG into its carbon dioxide equivalent, are considered "major sources" subject to PSD requirements if they propose to make modifications resulting in a net GHG emissions increase of 75,000 tons per year or more of CO2e. OTP does not anticipate making modifications at any of its facilities that would trigger PSD requirements. The South Dakota DENR reviewed OTP's projected emissions, including GHG emissions, as a result of the Big Stone 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 is developing NSPS for GHGs from electric generating units. The EPA proposed a rule on April 13, 2012 that would require certain new fossil fuel generating plants to meet a CO2 output based standard. Unlike traditional NSPS rules, the proposed GHG NSPS would not apply to modifications at existing units. It is expected that EPA will issue a final rule in the first half of 2013.

After EPA develops the NSPS, it is anticipated that the EPA will work towards issuing 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. However, annual updates of the range are required, and for 2012 and 2013 the range was revised to $9-$34/ton, and the start date to begin using CO2 costs in resource planning decisions was moved from 2012 to 2017.

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

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

Supply efficiency and reliability: Between 1990 and 2012, OTP decreased its CO2 intensity (lbs. of CO2/megawatt-hour generated) by nearly 25%.

Conservation: Since 1992 OTP has helped our customers conserve over 500 MW of demand and nearly 2.5 million cumulative megawatt-hours of electricity. That is roughly equivalent to the amount of electricity that 189,000 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. 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 CO_2 emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset credits, or the imposition of a carbon tax or cap and trade program at the state or federal level could materially adversely affect the Company’s future results of operations, cash flows, and possibly financial condition, unless such costs could be recovered through regulated rates and/or future market prices for energy.

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

On February 16, 2004 the EPA Administrator signed the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. A proposed 316(b) rule was issued on April 20, 2011 to replace the 2004 Phase II rule for existing facilities following its remand by the U.S. Court of Appeals in 2007. Unlike the 2004 Phase II rule, the proposed rule has the potential to affect both Hoot Lake Plant and Coyote Station with the greatest potential effect on Hoot Lake Plant. The final rule is due to be issued in June 2013. 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 2012, approximately $102 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2012 gross electric property additions, including construction work in progress, were approximately $495 million and gross retirements were approximately $58 million. OTP estimates that during the five-year period 2013-2017 it will invest approximately $811 million for electric construction, which includes $247 million for OTP’s share of a new Big Stone Plant AQCS and $348 million for transmission projects including $253 million for MVPs and $45 million for CapX2020 transmission projects, excluding $20 million for the Brookings to Southeast Twin Cities CapX2020 MVP project, included in the $253 million above. The remainder of the 2013-2017 anticipated capital expenditures is for asset replacements, additions and improvements across OTP’s generation, transmission, distribution and general plant.

Franchises

At December 31, 2012 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, 2012 OTP had 663 equivalent full-time employees. A total of 393 OTP employees are represented by local unions of the International Brotherhood of Electrical Workers under two separate contracts expiring in the fall of 2013 and 2014. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

MANUFACTURING

General

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

The Company derived 24%, 23% and 20% of its consolidated operating revenues from the Manufacturing segment for each of the three years ended December 31, 2012, 2011 and 2010, 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.

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, technical innovation, cost effectiveness, customer service and breadth of product line. The Company's manufacturing entities intend to continue to compete on the basis of high-performance products, innovative production technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

Raw Materials Supply

The companies in the Manufacturing segment use raw materials in the products they manufacture, including steel, aluminum and Polystyrene (PS) and other plastics resins. Both pricing increases and availability of these raw materials are concerns of companies in the Manufacturing segment. The companies in the Manufacturing segment attempt to pass increases in the costs of these raw materials on to their customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins in the Manufacturing segment.

Backlog

The Manufacturing segment has backlog in place to support 2013 revenues of approximately $124 million compared with $115 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 2012, cash expenditures for capital additions in the Manufacturing segment were approximately $9 million. Total capital expenditures for the Manufacturing segment during the five-year period 2013-2017 are estimated to be approximately $73 million.

Employees

At December 31, 2012 the Manufacturing segment had 980 full-time employees. There are 829 full-time employees at BTD and 151 full-time employees at T.O. Plastics.

CONSTRUCTION

General

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

The Company derived 17%, 22% and 19% of its consolidated operating revenues from the Construction segment for each of the years ended December 31, 2012, 2011 and 2010, respectively. Following is a brief description of the businesses included in this segment:

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

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

Competition

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

Backlog

The construction companies have backlog in place of $151 million for 2013 compared with $106 million one year ago.

Capital Expenditures

Capital expenditures in this segment typically include investments in additional construction equipment. During 2012, cash expenditures for capital additions in the Construction segment were approximately $2 million. Capital expenditures during the five-year period 2013-2017 are estimated to be approximately $12 million for the Construction segment.

Employees

At December 31, 2012 there were 446 full-time employees in the Construction segment. Foley has 203 employees represented by various unions, including Carpenters and Millwrights, Sheet Metal Workers, Laborers, Operators, Operating Engineers, Pipe Fitters, Steamfitters, Plumbers and Teamsters. Foley has several labor contracts with various expiration dates in 2013 – 111 employees, and 2014 – 90 employees, and one contract covering two employees that expires on May 31, 2017. Foley has not experienced any strike, work stoppage or strike vote, and considers its 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 18%, 15% and 14% of its consolidated operating revenues from the Plastics segment for each of the three years ended December 31, 2012, 2011 and 2010, 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 90% and 97% of total resin purchases in 2012 and 2011, 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 2012, cash expenditures for capital additions in the Plastics segment were approximately $3 million. Total capital expenditures for the five-year period 2013-2017 are estimated to be approximately $10 million to replace existing equipment.

Employees

At December 31, 2012 the Plastics segment had 142 full-time employees. Northern Pipe had 91 full-time employees and Vinyltech had 51 full-time employees as of December 31, 2012.

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 made a $10.0 million discretionary contribution to our defined benefit pension plan in January 2013. We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

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

We had approximately $39.0 million of goodwill recorded on our consolidated balance sheet as of December 31, 2012. 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.

We currently have $7.3 million of goodwill and a $1.1 million indefinite-lived trade name recorded on our consolidated balance sheet related to the acquisition of Foley in 2003. Foley generated a large operating loss in 2012 due to significant cost overruns on certain construction projects. If operating margins do not meet our projections, the reductions in anticipated cash flows from Foley may indicate that its fair value is less than its book value, resulting in an impairment of some or all of the goodwill and indefinite-lived trade name associated with Foley along with a corresponding charge against earnings.

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

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

Under our $150 million revolving credit agreement we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00. OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 under its $170 million revolving credit agreement. Both credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. As of December 31, 2012 we were in compliance with the debt covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes “funds properly included in a capital account” is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. The MPUC indirectly limits the amount of dividends OTP can pay to us by requiring an equity-to-total-capitalization ratio between 46.3% and 56.7%. OTP's equity-to-total-capitalization ratio was 52.0% as of December 31, 2012.

While these restrictions are not expected to affect our ability to pay dividends at the current level in the foreseeable future, there is no assurance that adverse financial results would not reduce or eliminate our ability to pay dividends. Our dividend payout ratio has exceeded our (losses) earnings in each of the last five years.

Economic conditions could negatively impact our businesses.

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

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

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

Our plans to grow and realign our business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.

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

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

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

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

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

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

Significant warranty claims and remediation costs in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition.

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

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

We are subject to risks associated with energy markets.

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

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

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

We rely on our information systems to conduct our business, and failure to protect these systems against security breaches 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, or to meet covenants under our borrowing agreements.

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

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

We are subject to federal and state legislation, government regulations and regulatory actions that may have a negative impact on our business and results of operations. The electric rates that OTP is allowed to charge for its electric services are one of the most important items influencing our financial position, results of operations and liquidity. The rates that OTP charges its electric customers are subject to review and determination by state public utility commissions in Minnesota, North Dakota and South Dakota. OTP is also regulated by the FERC. An adverse decision by one or more regulatory commissions concerning the level or method of determining electric utility rates, the authorized returns on equity, implementation of enforceable federal reliability standards or other regulatory matters, permitted business activities (such as ownership or operation of nonelectric businesses) or any prolonged delay in rendering a decision in a rate or other proceeding (including with respect to the recovery of capital expenditures in rates) could result in lower revenues and net income.

Depending on the outcome of the 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 is developing standards for GHGs from electric generating units and proposed a rule on April 13, 2012 that would require certain new fossil fuel generating plants to meet a CO_2 output based standard. Unlike traditional NSPS rules, the proposed GHG NSPS would not apply to modifications at existing units. It is expected that EPA will issue a final rule in the first half of 2013. Specific requirements of regulation under the CAA's various programs, and thus their impact on OTP, are uncertain at this time.

MANUFACTURING

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

Our manufacturing businesses are subject to intense risks associated with competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development staffs and facilities and other capabilities that may place downward pressure on margins and profitability. The companies in our Manufacturing segment use a variety of raw materials in the products they manufacture, including steel, aluminum and Polystyrene (PS) and other plastics resins. Costs for these items have increased significantly and may continue to increase. If our manufacturing businesses are not able to pass on cost increases to their customers, it could have a negative effect on profit margins in our Manufacturing segment.

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

CONSTRUCTION

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

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

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

Our construction companies frequently provide services pursuant to fixed-price contracts. Revenues recognized on jobs in progress under fixed-price contracts were $309 million at December 31, 2012 and $343 million at December 31, 2011. Under those contracts, we agree to perform the contract for a fixed price and, as a result, can improve our expected profit by superior contract performance, productivity, worker safety and other factors resulting in cost savings. However, we could incur cost overruns above the approved contract price, which may not be recoverable.

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

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 90% of our total purchases of PVC resin in 2012 and approximately 97% of our total purchases of PVC resin in 2011. 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, 2012 OTP’s transmission facilities, which are interconnected with lines of other public utilities, consisted of 76 miles of 345 kV lines; 487 miles of 230 kV lines; 862 miles of 115 kV lines; and 3,977 miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of 48 miles of the 345 kV lines, with Minnkota Power Cooperative retaining title to the original 230 kV construction. OTP owns an undivided interest in the remaining 345 kV line miles.

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

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

Item 3. LEGAL PROCEEDINGS

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

Item 3A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF FEBRUARY 27, 2013)

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

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
Edward J. McIntyre (62)	9/8/11	Present:	President and Chief Executive Officer
George A. Koeck (60)	4/10/00	Present:	Senior Vice President, General Counsel and Corporate Secretary
Kevin G. Moug (53)	4/9/01	Present:	Chief Financial Officer and Senior Vice President
Charles S. MacFarlane (48)	5/1/03	Present:	Senior Vice President, Electric Platform
Shane N. Waslaski (37)	4/11/11	Present:	Senior Vice President, Manufacturing and 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, 62, is retired Vice President and former Chief Financial Officer of Xcel Energy, Inc. He has been a member of the Board of Directors since 2006.

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

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

Item 4. MINE SAFETY DISCLOSURES

Not Applicable.

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 38 of this Annual Report on Form 10-K under the heading "Selected Financial Data," on Page 100 under the heading "Retained Earnings and Dividend Restriction" and on Page 120 under the heading "Supplementary Financial Information." The Company does not have a publicly announced stock repurchase program. In addition, the Company did not repurchase any equity securities during the three months ended December 31, 2012.

PERFORMANCE GRAPH
COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

This graph compares the cumulative total shareholder return on the Company's common shares for the last five fiscal years with the cumulative return of The NASDAQ Stock Market Index and the Edison Electric Institute Index (EEI) over the same period (assuming the investment of $100 in each vehicle on December 31, 2007, and reinvestment of all dividends).

	2007	2008	2009	2010	2011	2012
OTC	$100.00	$ 70.07	$ 78.76	$ 75.73	$ 78.26	$ 93.54
EEI	$100.00	$ 74.10	$ 82.03	$ 87.80	$105.35	$107.55
NASDAQ	$100.00	$ 61.67	$ 87.93	$104.13	$104.69	$123.85

Item 6. SELECTED FINANCIAL DATA

(thousands, except number of shareholders and per-share data)	2012	2011	2010	2009	2008
Revenues					
Electric	$ 350,765	$ 342,727	$ 344,379	$ 314,666	$ 340,075
Manufacturing	208,965	189,459	143,072	119,255	156,699
Construction	149,092	184,657	134,222	103,831	157,053
Plastics	150,517	123,669	96,945	80,208	116,452
Corporate Revenues and Intersegment Eliminations	(100)	(343)	(721)	(275)	(440)
Total Operating Revenues	$ 859,239	$ 840,169	$ 717,897	$ 617,685	$ 769,839
Net Income from Continuing Operations	$ 38,968	$ 34,910	$ 26,280	$ 22,131	$ 30,700
Net (Loss) Income from Discontinued Operations	(44,241)	(48,153)	(27,624)	3,900	4,425
Net (Loss) Income	$ (5,273)	$ (13,243)	$ (1,344)	$ 26,031	$ 35,125
Operating Cash Flow from Continuing Operations	$ 168,986	$ 93,678	$ 105,934	$ 125,646	$ 92,767
Operating Cash Flow - Continuing and Discontinued Operations	233,547	104,383	105,017	162,750	111,321
Capital Expenditures - Continuing Operations	115,762	67,360	58,264	160,501	217,604
Total Assets	1,602,337	1,700,522	1,770,555	1,754,678	1,692,587
Long-Term Debt	421,680	471,915	430,807	431,083	333,940
Basic Earnings Per Share - Continuing Operations (1)	1.06	0.95	0.71	0.60	0.95
Basic (Loss) Earnings Per Share - Total (1)	(0.17)	(0.40)	(0.06)	0.71	1.09
Diluted Earnings Per Share - Continuing Operations (1)	1.05	0.95	0.71	0.60	0.95
Diluted (Loss) Earnings Per Share - Total (1)	(0.17)	(0.40)	(0.06)	0.71	1.09
Return on Average Common Equity	(1.1)%	(2.3)%	(0.3)%	3.8 %	6.0 %
Dividends Declared Per Common Share	1.19	1.19	1.19	1.19	1.19
Dividend Payout Ratio	—	—	—	168 %	109 %
Common Shares Outstanding - Year End	36,168	36,102	36,003	35,812	35,385
Number of Common Shareholders (2)	14,584	14,687	14,848	14,923	14,627

(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 four segments: Electric, 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, which will lower our overall risk, create a more predictable earnings stream, improve our credit quality and preserve our ability to fund the dividend. Over time, we expect the electric utility business will provide approximately 75% to 85% of our overall earnings. We expect our manufacturing and infrastructure businesses will provide 15% to 25% of our earnings, and will continue to be a fundamental part of our strategy.

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

We have worked to realign our portfolio of businesses and refocus our capital investment in the electric utility. In 2011 and 2012 we sold several businesses in execution of our announced strategy. In 2011 we sold Idaho Pacific Holdings, Inc. (IPH), our Food Ingredient Processing segment business, and E.W. Wylie Corporation (Wylie), our trucking company which was included in our Wind Energy segment. In January 2012 we sold the assets of Aviva Sports, Inc. (Aviva), a recreational equipment manufacturer and wholly owned subsidiary of ShoreMaster, Inc. (ShoreMaster), our waterfront equipment manufacturer. In February 2012 we sold DMS Health Technologies, Inc. (DMS), our Health Services segment business. In November 2012 we completed the sale of the assets of DMI Industries, Inc. (DMI), our manufacturer of towers for wind turbines and exited the wind tower manufacturing business. In December 2012 we entered into negotiations to sell substantially all of the assets of ShoreMaster and completed the sale on February 8, 2013. As a result of these 2011, 2012 and 2013 transactions, our business structure no longer includes Wind Energy, Health Services or Food Ingredient Processing segments, and now includes the remaining four 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 $906 million for the years 2013 through 2017, of which $811 million are for capital projects at Otter Tail Power Company (OTP), including $247 million for OTP's share of a new air quality control system at Big Stone Plant and $348 million for anticipated expansion of transmission capacity including $253 million for MVPs and $45 million for CapX2020 transmission projects, excluding $20 million for the Brookings to Southeast Twin Cities CapX2020 MVP project, included in the $253 million above. The remainder of the 2013-2017 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant. See "Capital Requirements" section for further discussion.
- Utilization of existing and potentially expanded plant capacity from capital investments made in our manufacturing and infrastructure businesses.
- Continued investigation and evaluation of organic growth opportunities and evaluation of opportunities to allocate capital to potential acquisitions in our Manufacturing segment.

In 2012:

- Our net cash from continuing and discontinued operations was $233.5 million.
- Our Plastics segment net income increased 142.9% to $14.1 million.
- Our Manufacturing segment net income increased 29.7% to $10.7 million.

Our Electric segment net income of $38.3 million decreased slightly from $38.9 million in 2011.

Our Construction segment recorded a net loss of $7.7 million compared with a net loss of $2.2 million in 2011. Net income from Aevenia, Inc. (Aevenia), our electrical design and construction services company, increased $2.2 million while Foley Company (Foley), our mechanical and prime contractor on industrial projects, recorded a net loss increase of $7.7 million as a result cost overruns on several large jobs.

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

(in thousands)	2012	2011
Operating Revenues:		
Electric	$ 350,679	$ 342,633
Manufacturing and Infrastructure	508,560	497,536
Total Operating Revenues	$ 859,239	$ 840,169
Net Income (Loss) From Continuing Operations:		
Electric	$ 38,341	$ 38,886
Manufacturing and Infrastructure	17,100	11,836
Corporate	(16,473)	(15,812)
Total Net Income From Continuing Operations:	$ 38,968	$ 34,910

Revenue increases in our Plastics, Manufacturing and Electric segments were partially offset by a decrease in revenues from our Construction segment, resulting in a 2.3% increase in consolidated revenues in 2012 compared with 2011. Revenues from our Plastics segment increased $26.8 million as a result of a combination of increased sales volume and higher prices per pound of polyvinyl chloride (PVC) pipe sold. Revenues from our Manufacturing segment increased $19.5 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 Electric segment increased $8.0 million as a result of: (1) a $4.3 million increase in retail revenue, reflecting increases in transmission cost recovery revenues and revenues from Minnesota customers following implementation of new rates in October 2011, and (2) a $3.6 million increase in Midwest Independent Transmission System Operator (MISO) Schedule 26 transmission tariff revenues, driven in part by returns on, and recovery of, CapX2020 investment costs and operating expenses. Revenues from our Construction segment decreased $35.6 million as Foley's job volume and revenues recognized on a percentage-of-completion basis declined.

The following table sets forth actual 2012 consolidated diluted earnings per share results against the last forecast we provided for 2012 on a GAAP basis, and also shows the effect on a non-GAAP basis of the early retirement of our $50 million, 8.89% Senior Unsecured Note due 2017 (the Cascade Note).

	2012 Earnings Per Share Guidance Range November 5, 2012				
	Low	High	2012 GAAP Earnings Per Share	2012 Non-GAAP Items	2012 Non-GAAP Earnings Per Share
Electric	$1.01	$1.06	$1.06	--	$1.06
Manufacturing (without ShoreMaster)	$0.26	$0.30	$0.29	--	$0.29
Net Loss from ShoreMaster	($0.08)	($0.07)	--	--	--
Construction	($0.23)	($0.18)	($0.21)	--	($0.21)
Plastics	$0.32	$0.37	$0.39	--	$0.39
Corporate – Recurring Costs	($0.22)	($0.17)	($0.26)	$0.04	($0.22)
Subtotal	$1.06	$1.31	$1.27	$0.04	$1.31
Corporate – Premium Paid on Debt Extinguishment	($0.22)	($0.22)	($0.22)	$0.22	--
Total – Continuing Operations	$0.84	$1.09	$1.05	$0.26	$1.31
Discontinued Operations:					
Net Losses from Discontinued Operations	($1.00)	($0.95)	($1.22)	--	($1.22)
Premium Paid on Debt Extinguishment in Connection with DMI Disposition1	--	--	--	($0.22)	($0.22)

2012 Interest Expense on Debt Extinguished in Connection with DMI Disposition1	--	--	--	($0.04)	($0.04)
Total – Discontinued Operations	($1.00)	($0.95)	($1.22)	($0.26)	($1.48)
Total	($0.16)	$0.14	($0.17)	--	($0.17)

1We retired early the Cascade Note from proceeds generated in connection with the divestiture of DMI. Generally Accepted Accounting Principles require that in order for debt retirement premiums and related interest expense to be reported as discontinued operations, a company must be required by the lender to repay the related debt as a result of the disposition. Although we were not legally obligated to repay the aforementioned note, we believe it is appropriate to associate the 2012 debt prepayment premium and interest expense with our discontinued operations to provide a better indication of future earnings.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2012, 2011 and 2010, followed by a discussion of our financial position at the end of 2012 and our outlook for 2013.

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 2012, 2011 and 2010 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)	2012	2011	2010
Operating Revenues:			
Electric	$ 86	$ 94	$ 115
Nonelectric	14	249	606
Cost of Goods Sold	68	122	(57)
Other Nonelectric Expenses	32	221	778

ELECTRIC

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

(in thousands)	2012	% change	2011	% change	2010
Retail Sales Revenues	$308,530	1	$304,181	--	$305,146
Wholesale Revenues – Company Generation	12,951	(11)	14,518	(28)	20,053
Net Revenue – Energy Trading Activity	1,426	(39)	2,319	(26)	3,144
Other Revenues	27,858	28	21,709	35	16,036
Total Operating Revenues	$350,765	2	$342,727	--	$344,379
Production Fuel	66,284	(4)	69,017	(6)	73,102
Purchased Power – System Use	49,184	13	43,451	(3)	44,788
Other Operation and Maintenance Expenses	121,069	4	115,863	3	112,174
Asset Impairment	432	(8)	470	--	--
Depreciation and Amortization	42,051	4	40,283	--	40,241
Property Taxes	10,720	5	10,190	9	9,364
Operating Income	$61,025	(4)	$63,453	(2)	$64,710

Electric kilowatt-hours (kwh) Sales (in thousands)	2012	% change	2011	% change	2010
Retail kwh Sales	4,240,789	(1)	4,291,637	1	4,262,748
Wholesale kwh Sales – Company Generation	476,637	(7)	510,978	(18)	624,153
Wholesale kwh Sales – Purchased Power Resold	88,637	(28)	122,430	(64)	336,875

2012 compared with 2011
Retail sales revenues increased by $4.3 million as a result of:

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

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

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

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

offset by:

a $2.3 million decrease in revenues related to a 1.2% reduction in retail kwh sales between the periods due to an 11% reduction in heating-degree days resulting from significantly milder weather in the first half of 2012 compared to the first half of 2011, partially offset by a 19.6% increase in cooling-degree days in the summer of 2012 compared with the same period in 2011, and

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

Wholesale electric revenues from company-owned generation decreased $1.6 million due to a 6.7% decline in wholesale kwh sales in combination with a 4.4% decrease in the average price per wholesale kwh sold. This was related to an 8.7% reduction in kwh generation mainly as a result of two major shutdowns of OTP's lowest-cost baseload resource, Coyote Station, in 2012. The first occurred in the second quarter of 2012 for seven weeks of scheduled maintenance, and the second occurred on November 27, 2012, when an electrical fault caused major damage to the station's generator, which needed to be moved offsite for repairs estimated to take 10 to 12 weeks. Lower demand in wholesale markets and low natural gas prices for alternative generation also contributed to the reduction in wholesale electric sales.

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

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

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

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

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

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

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

offset by:

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

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

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

a $3.4 million increase in MISO transmission service charges, mainly MISO Schedule 26 charges related to increased investment in transmission facilities by MISO member companies, a $2.2 million increase in labor and benefit expenses mainly due to increases in pension and retiree health benefit costs resulting from a reduction in the discount rate applied to projected benefit obligations,

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

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

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

offset by:

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

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

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

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

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

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 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 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 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 Conservation Improvement Program (MNCIP) 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.

MANUFACTURING

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

(in thousands)	2012	% change	2011	% change	2010
Operating Revenues	$ 208,965	10	$ 189,459	32	$ 143,072
Cost of Goods Sold	157,437	9	144,987	37	106,114
Other Operating Expenses	18,233	10	16,524	15	14,343
Depreciation and Amortization	12,208	1	12,116	6	11,430
Operating Income	$ 21,087	33	$ 15,832	42	$ 11,185

2012 compared with 2011

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

Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, increased $17.7 million (11.8%) as a result of higher sales volume due to improved customer demand for products and services.

Revenues at T.O. Plastics, Inc. (T.O. Plastics) our manufacturer of thermoformed plastic and horticultural products, increased by $1.8 million (4.6%) mainly as a result of increased sales of industrial and medical products.

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

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

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

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

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

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

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

Revenues at BTD increased $44.7 million (42.1%) as a result of higher sales volume due to improved customer demand for products and services.

Revenues at T.O. Plastics 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 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 increase in other operating expenses in our Manufacturing segment in 2011 compared with 2010 relates to the following:

Operating expenses at BTD increased $2.0 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 T.O. Plastics increased $0.2 million due to increased salary and benefit costs and insurance costs offset by a reduction in advertising expenses.

CONSTRUCTION

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

(in thousands)	2012	% change	2011	% change	2010
Operating Revenues	$ 149,092	(19)	$ 184,657	38	$ 134,222
Cost of Goods Sold	147,107	(15)	173,654	44	120,470
Operating Expenses	12,353	4	11,886	(3)	12,235
Depreciation and Amortization	1,906	(5)	2,009	(1)	2,023
Operating Loss	$ (12,274)	(324)	$ (2,892)	(472)	$ (506)

2012 compared with 2011

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

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

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

The decrease in cost of goods sold in our Construction segment in 2012 compared with 2011 relates to the following:

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

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

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

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

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

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

- Revenues at Foley increased $48.7 million (52.3%) due to an increase in construction activity.
- Revenues at Aevenia 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 to 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.

PLASTICS

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

(in thousands)	2012	% change	2011	% change	2010
Operating Revenues	$ 150,517	22	$ 123,669	28	$ 96,945
Cost of Goods Sold	112,662	9	103,131	24	82,866
Operating Expenses	8,784	41	6,210	20	5,174
Depreciation and Amortization	3,118	(8)	3,377	(2)	3,430
Operating Income	$ 25,953	137	$ 10,951	100	$ 5,475

2012 compared with 2011

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

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.

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)	2012	% change	2011	% change	2010
Operating Expenses	$ 13,283	(11)	$ 14,897	(5)	$ 15,741
Depreciation and Amortization	481	(13)	550	5	523

Corporate operating expenses were lower in 2012 than in 2011 as a result of termination benefits incurred in the third quarter of 2011 associated with the resignation of the corporation's former chief executive officer and reductions in health benefit costs. Corporate operating expenses were lower in 2011 than in 2010 as a result of severance costs related to personnel changes incurred in 2010.

CONSOLIDATED OTHER INCOME

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

Other income increased $1.0 million in 2011 compared with 2010, mainly due to a $0.9 million increase in AFUDC.

LOSS ON EARLY RETIREMENT OF DEBT

On July 13, 2012 we prepaid in full the Cascade Note. The price to prepay the Cascade Note was $63,031,000, which included the principal amount of the Cascade Note plus accrued interest of $531,000 and a negotiated prepayment premium of $12,500,000. On repayment, $606,000 in unamortized debt expense related to this note was immediately recognized as expense along with the $12,500,000 negotiated prepayment premium. The $13,106,000 ($7,864,000 net-of-tax) loss on early retirement of debt had a negative impact on 2012 diluted earnings per share of $0.22.

CONSOLIDATED INTEREST CHARGES

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

Interest charges decreased $1.2 million in 2011 compared with 2010 due to a $0.6 reduction in the amortization of debt issuance expense and reacquisition losses and a $0.6 million increase in capitalized interest charges related to an increase in construction work in progress between the years.

CONSOLIDATED INCOME TAXES

Income tax expense - continuing operations was $2.1 million in 2012 compared with $4.1 million in 2011 and $3.2 million in 2010. The following table provides a reconciliation of income tax expense – continuing operations calculated at the federal statutory rate on income from continuing operations before income taxes reported on our consolidated statements of income for the years ended December 31, 2012, 2011 and 2010:

	For the Year Ended December 31,		
(in thousands)	2012	2011	2010
Tax Computed at Federal Statutory Rate	$14,385	$13,661	$10,329
Increases (Decreases) in Tax from:			
Federal Production Tax Credit	(6,695)	(7,281)	(6,441)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(891)	(996)	(1,163)
State Income Taxes Net of Federal Income Tax Benefit	(849)	798	(1,186)
Investment Tax Credit Amortization	(720)	(855)	(926)
Dividend Received/Paid Deduction	(656)	(677)	(692)
Corporate Owned Life Insurance	(585)	(388)	(556)
Impact of Medicare Part D Change	(584)	(599)	1,692
Allowance for Funds Used During Construction - Equity	(409)	(301)	(1)
Tax Depreciation - Treasury Grant for Wind Farms	(304)	(507)	(845)
Differences Reversing in Excess of Federal Rates	(143)	680	989
Permanent and Other Differences	(416)	586	2,031

Total Income Tax Expense – Continuing Operations	$2,133	$4,121	$3,231
Effective Income Tax Rate – Continuing Operations	5.2 %	10.6 %	10.9 %

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

DISCONTINUED OPERATIONS

On February 8, 2013 we closed on the sale of substantially all of the assets of ShoreMaster for approximately $13.0 million in cash, plus a future working capital true up to be finalized and paid no later than 180 days after closing. We recorded a $4.6 million net-of-tax impairment of ShoreMaster's assets in December 2012 based on the market value of ShoreMaster's assets. On November 30, 2012 we completed the sale of the fixed assets of DMI for total proceeds, net of commissions and selling costs, of $18.1 million. On February 29, 2012 we completed the sale of DMS, for $24.0 million net of commissions and selling cost. On January 18, 2012, we sold the assets of Aviva for $0.3 million in cash. For discontinued operations reporting, Aviva's results are included in ShoreMaster's consolidated results.

On December 29, 2011 we completed the sale of Wylie for approximately $25.0 million in cash. On May 6, 2011 we completed the sale of IPH for approximately $86.0 million in cash.

The financial position, results of operations, and cash flows of DMI, Wylie, ShoreMaster, DMS and IPH are reported as discontinued operations in our consolidated financial statements. Following are summary presentations of the results of discontinued operations for the years ended December 31, 2012, 2011 and 2010:

	For the Year Ended December 31, 2012						
(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Intercompany transactions adjustment	Total
Operating Revenues	$186,151	$--	$32,563	$16,362	$--	$(2,017)	$233,059
Operating Expenses	184,462	179	36,163	14,741	--	(2,017)	233,528
Asset Impairment Charge	45,573	--	7,747	--	--	--	53,320
Other Income	135	--	15	122	--	--	272
Interest Expense	5,787	--	1,553	279	--	(7,444)	175
Income Tax (Benefit) Expense	(15,792)	13	(4,021)	1,734	106	2,978	(14,982)
Net Loss from Operations	(33,744)	(192)	(8,864)	(270)	(106)	4,466	(38,710)
Loss on Disposition Before Taxes	--	(62)	--	(5,154)	--	--	(5,216)
Income Tax Expense (Benefit) on Disposition	--	460	--	(145)	--	--	315
Net Loss on Disposition	--	(522)	--	(5,009)	--	--	(5,531)
Net Loss	$(33,744)	$(714)	$(8,864)	$(5,279)	$(106)	$4,466	$(44,241)

	For the Year Ended December 31, 2011						
(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Intercompany transactions adjustment	Total
Operating Revenues	$201,921	$49,884	$39,863	$89,558	$28,125	$(6,016)	$403,335
Operating Expenses	218,542	55,927	41,478	85,244	24,046	(6,016)	419,221
Asset Impairment Charge	3,142	--	456	56,379	--	--	59,977
Other (Deductions) Income	(46)	18	1	281	(228)	(3)	23
Interest Expense	6,852	709	1,580	1,726	11	(10,636)	242
Income Tax (Benefit) Expense	(4,768)	(2,683)	(1,462)	(16,058)	1,462	4,254	(19,255)
Net (Loss) Income from Operations	(21,893)	(4,051)	(2,188)	(37,452)	2,378	6,379	(56,827)
(Loss) Gain on Disposition Before Taxes	--	(946)	--	--	15,471	--	14,525

Income Tax Expense on Disposition	--	2,854	--	--	2,997	--	5,851
Net (Loss) Gain on Disposition	--	(3,800)	--	--	12,474	--	8,674
Net (Loss) Income	$(21,893)	$(7,851)	$(2,188)	$(37,452)	$14,852	$6,379	$(48,153)

	For the Year Ended December 31, 2010						
(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Intercompany transactions adjustment	Total
Operating Revenues	$143,603	$54,143	$35,624	$100,301	$77,412	$(5,830)	$405,253
Operating Expenses	159,646	52,311	41,351	98,794	65,261	(5,830)	411,533
Asset Impairment Charge	--	--	19,740	--	--	--	19,740
Other (Deductions) Income	(734)	8	21	331	(326)	--	(700)
Interest Expense	5,614	522	1,492	1,289	111	(8,844)	184
Income Tax (Benefit) Expense	(356)	511	(7,058)	369	3,716	3,538	720
Net (Loss) Income	$(22,035)	$807	$(19,880)	$180	$7,998	$5,306	$(27,624)

IMPACT OF INFLATION

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

Our Manufacturing, 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, 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, 2012 and December 31, 2011:

(in thousands)	Line Limit	In Use on December 31, 2012	Restricted due to Outstanding Letters of Credit	Available on December 31, 2012	Available on December 31, 2011
Otter Tail Corporation Credit Agreement	$150,000	$--	$ 733	$149,267	$198,776
OTP Credit Agreement	170,000	--	3,189	166,811	165,950
Total	$320,000	$--	$ 3,922	$316,078	$364,726

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

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2012 we filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. On May 14, 2012, we entered into a Distribution Agreement (the Agreement) with J.P. Morgan Securities (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million. Equity or debt financing will be required in the period 2013 through 2017 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

Our common stock dividend payments have exceeded our net (losses) income in each of the last five years. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share to levels in excess of the indicated annual dividend per share of $1.19, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by the Company's subsidiaries. See note 8 to consolidated financial statement for more information. The decision to declare a quarterly dividend is reviewed quarterly by the Board of Directors.

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

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

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

CAPITAL REQUIREMENTS

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

Cash used for consolidated capital expenditures was $116 million in 2012, $67 million in 2011 and $58 million in 2010. Estimated capital expenditures for 2013 are $204 million. Total capital expenditures for the five-year period 2013 through 2017 are estimated to be approximately $906 million, which includes $247 million for OTP's share of a new air quality control system at Big Stone Plant and $347 million for transmission projects including $253 million for MVPs and $45 million for CapX2020 transmission projects, excluding $20 million for the Brookings to Southeast Twin Cities CapX2020 MVP project, included in the $253 million above.

The breakdown of 2010, 2011 and 2012 actual cash used for capital expenditures and 2013 through 2017 estimated capital expenditures by segment is as follows:

(in millions)	2010	2011	2012	2013	2014	2015	2016	2017	Total for 2013-2017
Electric	$ 43	$ 50	$ 102	$ 182	$ 185	$ 170	$ 113	$ 161	$ 811
Manufacturing	6	10	9	17	14	15	12	16	74
Construction	5	3	2	3	3	2	1	2	11
Plastics	3	2	3	2	2	2	2	2	10
Corporate	1	2	--	--	--	--	--	--	--
Total	$ 58	$ 67	$ 116	$ 204	$ 204	$ 189	$ 128	$ 181	$ 906

The following table summarizes our contractual obligations at December 31, 2012 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Coal Contracts (required minimums)	$ 797	$ 43	$ 37	$ 43	$ 674
Long-Term Debt Obligations	422	--	1	138	283
Interest on Long-Term Debt Obligations	250	26	53	43	128
Capacity and Energy Requirements	170	31	30	32	77
Postretirement Benefit Obligations	91	4	9	10	68
Other Purchase Obligations	79	45	12	22	--
Operating Lease Obligations	42	8	13	8	13
Total Contractual Cash Obligations	$ 1,851	$ 157	$ 155	$ 296	$ 1,243

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.

In January 2013 our Board of Directors authorized the redemption in full of all four series of our cumulative preferred shares, which were called on January 24, 2013 for redemption on March 1, 2013. Also, on January 24, 2013, OTP caused call notices to be issued for the optional redemption in full on March 1, 2013, all of the outstanding 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds (of which an aggregate of $5.1 million was outstanding on such date) and all of the outstanding 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds (of which an aggregate of $20.1 million was outstanding on such date), in each case for which OTP pays debt service. Additionally, on March 1, 2013 OTP will pay off $15.5 million in intercompany debt owed to us that represents our $15.5 million in cumulative preferred shares outstanding. All of the foregoing redemptions will be funded from a $40.9 million term loan OTP will be entering into. The lower, LIBOR based, floating rate interest under the term loan is expected to contribute to a reduction in pre-tax interest expense in 2013 compared with 2012.

CAPITAL RESOURCES

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

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

On May 14, 2012, we entered into the Agreement with JPMS. Pursuant to the terms of the Agreement, we may offer and sell our common shares from time to time through JPMS, as our distribution agent for the offer and sale of the shares, up to an aggregate sales price of $75 million. Under the Agreement, we will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. We are not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to our shelf registration statement, as amended. No shares have been sold pursuant to the Agreement.

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2012 and December 31, 2011:

(in thousands)	Line Limit	In Use on December 31, 2012	Restricted due to Outstanding Letters of Credit	Available on December 31, 2012	Available on December 31, 2011
Otter Tail Corporation Credit Agreement	$150,000	$ --	$ 733	$ 149,267	$ 198,776
OTP Credit Agreement	170,000	--	3,189	166,811	165,950
Total	$320,000	$ --	$ 3,922	$ 316,078	$ 364,726

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2012 was $66,236,000 on July 13, 2012 and the average daily balance of debt outstanding during 2012 was $12,078,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2012 was 3.8% compared with 3.7% in 2011. Under the OTP Credit Agreement, the maximum amount of debt outstanding in 2012 was $16,582,000 on August 15, 2012 and the average daily balance of debt outstanding during 2012 was $5,867,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2012 was 1.7% compared with 1.5% in 2011.

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Credit Agreement), which is an unsecured $150 million revolving credit facility that we can draw on to refinance certain indebtedness and support our operations and the operations of our subsidiaries. The Credit Agreement amends and restates our Second Amended and Restated Credit Agreement dated as of May 4, 2010, which was set to expire on May 4, 2013, and provided for a $200 million line of credit. Borrowings under the Credit Agreement bear interest at LIBOR plus 1.75%, subject to adjustment based on our senior unsecured credit ratings. The Credit Agreement expires on October 29, 2017. Under the Credit Agreement, we are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. 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, make investments, 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 $40 million. The Credit Agreement has an accordion feature whereby the line can be increased to $250 million on the terms and subject to the conditions described in the Credit Agreement.

On October 29, 2012 OTP entered into a Second 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 amends and restates the $170 million OTP Credit Agreement dated as of March 3, 2011, which was set to expire on March 3, 2016. 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 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. The OTP Credit Agreement is set to expire on October 29, 2017. 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, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

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. The entire principal amount of the notes, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016.

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 its 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.

On July 13, 2012, we prepaid in full the Cascade Note issued pursuant to the Note Purchase Agreement dated as of February 23, 2007, as amended, between us and Cascade Investment L.L.C. (Cascade). Immediately before the prepayment, the Cascade Note bore interest at 8.89% annually. The price paid by us to prepay the Cascade Note was $63,031,000, which included the principal amount of the Cascade Note plus accrued interest of $531,000 and a negotiated prepayment premium of $12,500,000. We used the funds available under the Credit Agreement for the prepayment. This early retirement reflects our desire to lower our long-term debt outstanding given our recent divestitures. This retirement of debt strengthens our consolidated capital structure and will positively affect future years' earnings by lowering interest costs. Cascade owned approximately 9.6% of our outstanding common stock as of December 31, 2012.

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 OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement.

The 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, and each contains a number of restrictions on OTP. These include restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

Financial Covenants

As of December 31, 2012 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, 2012 our Interest and Dividend Coverage Ratio calculated under the requirements of the Credit Agreement was 2.81 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.

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, 2012 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 3.35 to 1.00.

As of December 31, 2012 our interest-bearing debt to total capitalization was 0.44 to 1.00 on a fully consolidated basis and 0.48 to 1.00 for OTP.

Our ratio of earnings to fixed charges from continuing operations, which includes imputed finance costs on operating leases, was 2.6x for 2012 compared to 2.0x for 2011, and our debt interest coverage ratio before taxes was 2.2x for 2012 compared to 2.1x for 2011. During 2013, we expect these coverage ratios to increase, assuming 2013 net income meets our expectations.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $10.6 million, but our line of credit borrowing limits are only restricted by $3.9 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.

2013 BUSINESS OUTLOOK

We anticipate 2013 diluted earnings per share to be in the range of $1.30 to $1.55. This guidance reflects the current mix of businesses owned by us as we start out 2013. 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 2013 is in the range of $200 million to $210 million. This compares with $116 million of capital expenditures in 2012. The major project contributing to the increase in planned expenditures is the new air quality control system (AQCS) for Big Stone Plant to meet requirements of the federal Clean Air Act and regional haze regulations. We plan to invest in generation and transmission projects for the Electric segment that are expected to positively impact our earnings and returns on capital. In addition to the AQCS project, current Electric segment projects include investment in three MISO-determined MVP transmission projects that will serve the nine-state MISO region, of which one is a CapX2020 project already underway, and investment with other utilities in one other remaining CapX2020 transmission project also under way.

Segment components of our 2013 earnings per share guidance range are as follows:

	2012 EPS	2013 EPS Guidance	
	by Segment	Low	High
Electric	$1.06	$1.06	$1.11
Manufacturing	$0.29	$0.31	$0.36
Construction	($0.21)	$0.06	$0.11
Plastics	$0.39	$0.16	$0.21
Corporate	($0.26)	($0.29)	($0.24)
Subtotal – Continuing Operations	$1.27	$1.30	$1.55
Corporate – Premium Paid on Debt Extinguishment	($0.22)		
Total – Continuing Operations	$1.05	$1.30	$1.55

Contributing to our earnings guidance for 2013 are the following items:

We expect net income to increase slightly in our Electric segment in 2013 compared with 2012. This is based on rider recovery increases and an increase in AFUDC related to larger construction expenditures, offset by lower conservation improvement program incentives and increases in operating and maintenance expenses due to higher benefit costs. OTP's pension benefit costs for 2013 for our noncontributory funded pension plan are expected to increase by $2.7 million in 2013, reflecting a change in the assumed rate of return on pension plan assets from 8.0% in 2012 to 7.75% in 2013 and a decrease in the estimated discount rate used to determine annual benefit costs accruals from 5.15% in 2012 to 4.50% in 2013.

We expect earnings from our Manufacturing segment to improve in 2013 due to the following factors:

- o Increased order volume and continuing improvement in economic conditions in the industries BTD serves,
- o A slight increase in earnings from T.O. Plastics, and
- o Backlog for the manufacturing companies of approximately $124 million for 2013 compared with $115 million one year ago.

We expect higher net income from our Construction segment in 2013 as it has implemented improved cost control processes in construction management and selectively bid on projects with the potential for higher margins. 2012 was negatively impacted by the results on certain large projects at Foley. These projects are now substantially completed and Foley's internal bidding and estimating project review procedures have been improved such that we do not expect to see similar losses in 2013. Backlog in place for the construction businesses is $151 million for 2013 compared with $106 million one year ago.

The Plastics segment experienced its second best earnings year in its history in 2012 due in part to certain market and weather related events that are not expected to recur in 2013. Accordingly, we expect 2013 net earnings for Plastics to be lower based on the market and weather conditions currently being experienced.

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

The sales of DMI and ShoreMaster 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. 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 OTP, our most stable and relatively predictable business, and is consistent with the strategy to grow this business given its current investment opportunities.

The following table shows our 2012 capital expenditures and 2013 through 2017 anticipated capital expenditures and electric utility average rate base:

(in millions)	2012	2013	2014	2015	2016	2017
Capital Expenditures:						
Electric Segment:						
Transmission		$ 60	$ 45	$ 56	$ 69	$ 118
Environmental		89	99	72	1	--
Other		33	41	42	43	43
Total Electric Segment	$ 102	$ 182	$ 185	$ 170	$ 113	$ 161
Manufacturing and Infrastructure Segments	14	22	19	19	15	20
Total Capital Expenditures	$ 116	$ 204	$ 204	$ 189	$ 128	$ 181
Total Electric Utility Average Rate Base	$ 694	$ 789	$ 919	$ 1,061	$ 1,134	$ 1,197

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 2013 through 2017 timeframe. We intend to maintain our equity to total capitalization ratio near its present level of 52% 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.

Our outlook for 2013 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 2013 for our noncontributory funded pension plan is expected to be $10.5 million compared to $8.6 million in 2012, reflecting a change in the assumed rate of return on pension plan assets from 8.0% in 2012 to 7.75% in 2013, and a decrease in the estimated discount rate used to determine annual benefit cost accruals from 5.15% in 2012 to 4.50% in 2013. 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 2012, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2012 pension benefit cost by $736,000; a 0.25 decrease in the discount rate would have increased our 2012 pension benefit cost by $772,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2012 pension benefit cost by $706,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2012 pension benefit cost by $501,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2012 pension benefit cost by $451,000.

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 2012 postretirement medical benefit costs by $269,000. A 0.25 decrease in the discount rate would have increased our 2012 postretirement medical benefit costs by $285,000. See note 12 to our consolidated financial statements for the cost impact of a change in medical cost inflation rates.

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

REVENUE RECOGNITION
Our construction companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of costs incurred to total estimated costs. The duration of the majority of these contracts ranges from less than a year up to

three years. Revenues recognized on jobs in progress as of December 31, 2012 were $309 million. Any expected losses on jobs in progress at year-end 2012 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

We have a standard quarterly Estimate at Completion process in which we review the progress and performance of our contracts accounted for under percentage-of-completion accounting. As part of this process, our reviews include, but are not limited to, any outstanding key contract matters, progress towards completion and the related program schedule, identified risks and opportunities, and the related changes in estimates of revenues and costs. The risks and opportunities include our judgment about the ability and cost to achieve the schedule, technical requirements and other contract requirements. We must make assumptions regarding labor productivity and availability, the complexity of the work to be performed, the availability of materials, the length of time to complete the contract, and performance by subcontractors, among other variables. Based on this analysis, any adjustments to net sales, costs of sales, and the related impact to operating income are recorded as necessary in the period they become known. These adjustments may result from positive program performance and an increase in operating profit during the performance of individual contracts if management determines it will be successful in mitigating risks surrounding the technical, schedule, and cost aspects of those contracts or realizing related opportunities. Likewise, these adjustments may result in a decrease in operating profit if we determine we will not be successful in mitigating these risks or realizing related opportunities. Changes in estimates of net sales, costs of sales, and the related impact to operating income are recognized using a cumulative catch-up, which recognizes, in the current period, the cumulative effect of the changes on current and prior periods based on a contract’s percent complete. A significant change in one or more of these estimates could affect the profitability of one or more of our contracts. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

OTP’s forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under generally accepted accounting principles. 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, and, as such, are estimates. The forward energy sales contracts that are marked to market as of December 31, 2012, are 100% offset by forward energy purchase contracts in terms of volumes, delivery periods and points of delivery. 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 $49,000 on forward purchases and sales of electricity marked to market on December 31, 2012 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	1st Quarter 2013
Net Gain	$ 49

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 2012, for continuing operations, $845,000 of bad debt expense (0.1% of total 2012 revenue of $859.2 million) was recorded and the allowance for doubtful accounts was $1.3 million (1.4% of gross trade accounts receivable) as of December 31, 2012. 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, 2012 would result in a $0.9 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 2.98% in 2012, 2.94% in 2011 and 3.01% in 2010. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

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

TAXATION
We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2012 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of Accounting Standards Codification (ASC) 740, Income Taxes, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

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

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

difference between the fair value of the asset and the carrying amount of the asset.

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

In 2012, asset impairments were recorded at DMI, ShoreMaster and OTESCO. The DMI and ShoreMaster impairments were recorded in connection with their sales value and are reflected in the results of discontinued operations. As of December 31, 2012 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 $7.3 million of goodwill and a $1.1 million indefinite-lived trade name recorded on our balance sheet related to the acquisition of Foley in 2003. Foley generated a large operating loss in 2012 due to significant cost overruns on certain construction projects. If operating margins do not meet our projections, the reductions in anticipated cash flows from Foley may indicate that its fair value is less than its book value, resulting in an impairment of some or all of the goodwill and indefinite-lived intangible assets associated with Foley along with a corresponding charge against earnings.

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, 2012 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 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, 2012 we had no exposure to market risk associated with interest rates because we had no debt outstanding subject to variable interest rates.

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.

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

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

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2012 OTP had recognized, on a pretax basis, $49,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy purchase contracts that are marked to market as of December 31, 2012, are 100% offset by forward energy sales contracts in terms of volumes, delivery periods and points of delivery. The differential in forward prices at the different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy contracts of $49,000.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with our energy trading activities. Additionally, we have a Value at Risk (VaR) limit to further manage market price risk. There was no price risk on open positions as of December 31, 2012 because the open purchases were offset by open sales at the same point of delivery.

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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, 2012 and December 31, 2011, and the change in the Company's consolidated balance sheet position from December 31, 2011 to December 31, 2012 and December 31, 2010 to December 31, 2011:

(in thousands)	December 31, 2012	December 31, 2011
Current Asset – Marked-to-Market Gain	$ 502	$ 3,803
Regulatory Asset – Current Deferred Marked-to-Market Loss	7,949	5,208
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	10,050	10,749
Total Assets	18,501	19,760
Current Liability – Marked-to-Market Loss	(18,234)	(18,770)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(8)	(96)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(210)	--
Total Liabilities	(18,452)	(18,866)
Net Fair Value of Marked-to-Market Energy Contracts	$ 49	$ 894

(in thousands)	Year ended December 31, 2012	Year ended December 31, 2011
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	$ 894	$ 763
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(861)	(356)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(86)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	321
Changes in Fair Value of Contracts Entered into in Current Period	49	573
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 49	$ 894

The $49,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2012 is expected to be realized on settlement in the first quarter of 2013.

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

	Year Ended December 31,		
(in thousands)	2012	2011	2010
Net (Losses) Gains on Forward Electric Energy Contracts	$ (61)	$ 926	$ 2,135

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, 2012 was $285,000. As of December 31, 2012 OTP had a net credit risk exposure of $580,000 from five counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at December 31, 2012 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 $580,000 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, 2012. 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, 2012 and 2011, and the related consolidated statements of income, comprehensive income, common shareholders’ equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company’s internal control over financial reporting as of December 31, 2012 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 and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report Regarding Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company’s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements and financial statement schedule 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 and financial statement schedule referred to above present fairly, in all material respects, the financial position of Otter Tail Corporation and its subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, 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 27, 2013

OTTER TAIL CORPORATION

Consolidated Balance Sheets, December 31

(in thousands)	2012	2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$52,362	$15,994
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $1,279 for 2012 and $1,114 for 2011)	91,170	93,392
Other	7,684	8,660
Inventories	69,336	68,743
Deferred Income Taxes	30,964	9,523
Unbilled Revenue	15,701	13,719
Costs and Estimated Earnings in Excess of Billings	3,663	12,211
Regulatory Assets	25,499	27,391
Other	8,161	15,009
Assets of Discontinued Operations	19,092	209,929
Total Current Assets	323,632	474,571
Investments	9,471	11,093
Other Assets	26,222	26,997
Goodwill	38,971	39,118
Other Intangibles--Net	14,305	15,286
Deferred Debits		
Unamortized Debt Expense	5,529	6,458
Regulatory Assets	134,755	124,137
Total Deferred Debits	140,284	130,595
Plant		
Electric Plant in Service	1,423,303	1,372,534
Nonelectric Operations	186,094	177,328
Construction Work in Progress	77,890	52,751
Total Gross Plant	1,687,287	1,602,613
Less Accumulated Depreciation and Amortization	637,835	599,751
Net Plant	1,049,452	1,002,862
Total Assets	$1,602,337	$1,700,522

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

Consolidated Balance Sheets, December 31

(in thousands, except share data)	2012	2011
LIABILITIES AND EQUITY		
Current Liabilities		
Current Maturities of Long-Term Debt	$176	$165
Accounts Payable	88,406	80,457
Accrued Salaries and Wages	20,571	15,862
Billings In Excess Of Costs and Estimated Earnings	16,204	9,175
Accrued Taxes	12,047	11,696
Derivative Liabilities	18,234	18,770
Other Accrued Liabilities	6,334	5,540
Liabilities of Discontinued Operations	11,156	50,691
Total Current Liabilities	173,128	192,356
Pensions Benefit Liability	116,541	106,818
Other Postretirement Benefits Liability	58,883	48,263
Other Noncurrent Liabilities	22,244	18,102
Commitments and Contingencies (note 9)		
Deferred Credits		
Deferred Income Taxes	171,787	173,312
Deferred Tax Credits	31,299	33,182
Regulatory Liabilities	68,835	69,106
Other	466	520
Total Deferred Credits	272,387	276,120
Capitalization (page 70)		
Long-Term Debt, Net of Current Maturities	421,680	471,915
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2012 and 2011 – 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, 2012—36,168,368 Shares; 2011—36,101,695 Shares	180,842	180,509
Premium on Common Shares	253,296	253,123
Retained Earnings	92,221	141,248
Accumulated Other Comprehensive Loss	(4,385)	(3,432)
Total Common Equity	521,974	571,448
Total Capitalization	959,154	1,058,863

Total Liabilities and Equity	$1,602,337	$1,700,522

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)	2012	2011	2010
Operating Revenues			
Electric	$350,679	$342,633	$344,264
Nonelectric	508,560	497,536	373,633
Total Operating Revenues	859,239	840,169	717,897
Operating Expenses			
Production Fuel - Electric	66,284	69,017	73,102
Purchased Power - Electric System Use	49,184	43,451	44,788
Electric Operation and Maintenance Expenses	121,069	115,863	112,174
Cost of Goods Sold - Nonelectric (excludes depreciation; included below)	417,138	421,650	309,507
Other Nonelectric Expenses	52,621	49,296	46,715
Asset Impairment Charge	432	470	--
Depreciation and Amortization	59,764	58,335	57,647
Property Taxes - Electric	10,720	10,190	9,364
Total Operating Expenses	777,212	768,272	653,297
Operating Income	82,027	71,897	64,600
Loss on Early Retirement of Debt	13,106	--	--
Interest Charges	31,905	35,629	36,848
Other Income	4,085	2,763	1,759
Income Before Income Taxes – Continuing Operations	41,101	39,031	29,511
Income Tax Expense – Continuing Operations	2,133	4,121	3,231
Net Income from Continuing Operations	38,968	34,910	26,280
Discontinued Operations			
Loss - net of Income Tax Expense (Benefit) of $6,231, ($1,811) and $4,834 for the respective periods	(6,603)	(14,294)	(11,998)
Impairment Loss - net of Income Tax (Benefit) of ($21,213), ($17,444) and ($4,114) for the respective periods	(32,107)	(42,533)	(15,626)
(Loss) Gain on Disposition - net of Income Tax Expense of $315 in 2012 and $5,851 in 2011	(5,531)	8,674	--
Net Loss from Discontinued Operations	(44,241)	(48,153)	(27,624)
Total Net Loss	(5,273)	(13,243)	(1,344)
Preferred Dividend Requirement and Other Adjustments	736	1,058	833
Loss Available for Common Shares	$(6,009)	$(14,301)	$(2,177)
Average Number of Common Shares Outstanding--Basic	36,048	35,922	35,784
Average Number of Common Shares Outstanding--Diluted	36,242	36,082	36,012
Basic Earnings (Loss) Per Common Share:			
Continuing Operations (net of preferred dividend requirement)	$1.06	$0.95	$0.71
Discontinued Operations (net of other adjustments)	$(1.23)	$(1.35)	$(0.77)
	$(0.17)	$(0.40)	$(0.06)

Diluted Earnings (Loss) Per Common Share:			
Continuing Operations (net of preferred dividend requirement)	$1.05	$0.95	$0.71
Discontinued Operations (net of other adjustments)	$(1.22)	$(1.35)	$(0.77)
	$(0.17)	$(0.40)	$(0.06)
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)	2012	2011	2010
Net Loss	$(5,273)	$(13,243)	$(1,344)
Other Comprehensive Income (Loss):			
Unrealized Gain (Loss) on Available-for-Sale Securities:			
Net Gain (Loss) Arising During Period	154	(121)	50
Income Tax (Expense) Benefit	(53)	48	(20)
Net Gain (Loss) on Available-for-Sale Securities – net-of-tax	101	(73)	30
Foreign Currency Translation Adjustment Gain (Loss):			
Unrealized Net Change During Period	--	303	1,335
Reversal of Previously Recognized Gains Realized on Sale of IPH in 2011	--	(6,068)	--
Income Tax Benefit (Expense)	--	1,787	(15)
Foreign Currency Translation Adjustment (Loss) Gain – net-of-tax	--	(3,978)	1,320
Pension and Postretirement Benefit Plans:			
Actuarial (Losses) Gains Net of Regulatory Allocation Adjustment	(2,133)	(1,686)	1,738
Amortization of Unrecognized Postretirement Benefit Costs	376	239	682
Income Tax Benefit (Expense)	703	579	(968)
Pension and Postretirement Benefit Plans – net-of-tax	(1,054)	(868)	1,452
Total Other Comprehensive (Loss) Income	(953)	(4,919)	2,802
Total Comprehensive (Loss) Income	$(6,226)	$(18,162)	$1,458

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 Shares	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
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
Common Stock Issuances, Net of Expenses	71,745	359	148			507
Common Stock Retirements	(5,072)	(26)	(85)			(111)
Net Loss				(5,273)		(5,273)
Other Comprehensive Loss					(953)	(953)
Tax Benefit – Stock Compensation			(103)			(103)
Employee Stock Incentive Plan Expense			435			435
Premium on Purchase of Stock for Employee Purchase Plan			(222)			(222)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(43,018)		(43,018)
Balance, December 31, 2012	36,168,368	$180,842	$253,296	$92,221	$(4,385)(a)	$521,974

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

(in thousands) 2

Unrealized Gain on Marketable Equity Securities:

Before Tax	$1
Tax Effect	(6
Unrealized Gain on Marketable Equity Securities – Net-of-Tax	1
Foreign Currency Exchange Translation – Net-of-Tax:	
Before Tax	--
Tax Effect	--
Foreign Currency Exchange Translation – Net-of-Tax	--
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits:	
Before Tax	(7
Tax Effect	3
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits – Net-of-Tax	(4
Accumulated Other Comprehensive (Loss) Income:	
Before Tax	(7
Tax Effect	2
Net Accumulated Other Comprehensive (Loss) Income	$(4

See accompanying notes to consolidated financial statements.

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

(in thousands)	2012	2011	2010
Cash Flows from Operating Activities			
Net Loss	$(5,273)	$(13,243)	$(1,344)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities:			
Net Loss (Gain) from Sale of Discontinued Operations	5,531	(8,674)	--
Net Loss from Discontinued Operations	38,710	56,827	27,624
Depreciation and Amortization	59,764	58,335	57,647
Asset Impairment Charge	432	470	--
Deferred Tax Valuation Adjustments and Tax Rate Reduction	--	--	8,300
Premium Paid for Early Retirement of Long-Term Debt	12,500	--	--
Deferred Tax Credits	(2,091)	(2,386)	(2,715)
Deferred Income Taxes	11,459	10,661	10,990
Change in Deferred Debits and Other Assets	(4,802)	(25,053)	30
Discretionary Contribution to Pension Fund	(10,000)	--	(20,000)
Change in Noncurrent Liabilities and Deferred Credits	32,718	35,178	2,786
Allowance for Equity (Other) Funds Used During Construction	(1,168)	(861)	(4)
Change in Derivatives Net of Regulatory Deferral	718	72	208
Stock Compensation Expense – Equity Awards	1,311	2,177	2,923
Other—Net	4,500	6,496	5,847
Cash Provided by (Used for) Current Assets and Current Liabilities:			
Change in Receivables	2,430	(7,952)	(31,094)
Change in Inventories	(687)	(5,286)	(8,167)
Change in Other Current Assets	7,019	(1,072)	(6,559)
Change in Payables and Other Current Liabilities	30,056	(4,775)	16,256
Change in Interest Payable and Income Taxes Receivable/Payable	(14,141)	(7,236)	43,206
Net Cash Provided by Continuing Operations	168,986	93,678	105,934
Net Cash Provided by (Used in) Discontinued Operations	64,561	10,705	(917)
Net Cash Provided by Operating Activities	233,547	104,383	105,017
Cash Flows from Investing Activities			
Capital Expenditures	(115,762)	(67,360)	(58,264)
Proceeds from Disposal of Noncurrent Assets	4,889	1,923	827
Net Increase in Other Investments	(1,037)	(40)	(2,855)
Net Cash Used in Investing Activities - Continuing Operations	(111,910)	(65,477)	(60,292)
Net Proceeds from Sale of Discontinued Operations	42,229	107,310	--
Net Cash Used in Investing Activities - Discontinued Operations	(13,896)	(36,410)	(24,875)
Net Cash (Used in) Provided by Investing Activities	(83,577)	5,423	(85,167)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	--	(7,268)	7,268
Net Short-Term (Repayments) Borrowings	--	(79,490)	71,905
Proceeds from Issuance of Common Stock	--	--	549
Proceeds from Issuance of Class B Stock of Subsidiary	--	--	153
Common Stock Issuance Expenses	(370)	--	(142)
Payments for Retirement of Common Stock	(111)	(1,182)	(401)
Payments for Retirement of Class B Stock and Options of Subsidiary	--	--	(1,012)
Proceeds from Issuance of Long-Term Debt	--	142,006	--
Short-Term and Long-Term Debt Issuance Expenses	(897)	(1,666)	(1,699)

Payments for Retirement of Long-Term Debt	(50,224)	(100,796)	(58,451)
Premium Paid for Early Retirement of Long-Term Debt	(12,500)	--	--
Dividends Paid and Other Distributions	(43,976)	(43,923)	(43,698)
Net Cash Used in Financing Activities - Continuing Operations	(108,078)	(92,319)	(25,528)
Net Cash (Used in) Provided by Financing Activities - Discontinued Operations	(4,278)	(3,184)	1,812
Net Cash Used in Financing Activities	(112,356)	(95,503)	(23,716)
Net Change in Cash and Cash Equivalents - Discontinued Operations	(1,246)	2,015	(2,495)
Effect of Foreign Exchange Rate Fluctuations on Cash – Discontinued Operations	--	(324)	(566)
Net Change in Cash and Cash Equivalents	36,368	15,994	(6,927)
Cash and Cash Equivalents at Beginning of Period	15,994	--	6,927
Cash and Cash Equivalents at End of Period	$52,362	$15,994	$--

See accompanying notes to consolidated financial statements.

OTTER TAIL CORPORATION

Consolidated Statements of Capitalization, December 31 (in thousands, except share data)			2012	2011
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, retired early on July 13, 2012			--	50,000
North Dakota Development Note, 3.95%, due April 1, 2018			393	458
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021			1,332	1,431
Total – Otter Tail Corporation			101,725	151,889
Obligations of Otter Tail Power Company				
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			5,065	5,090
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			20,070	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
Total – Otter Tail Power Company			320,135	320,195
Total			421,860	472,084
Less:				
Current Maturities – Otter Tail Corporation			176	165
Unamortized Debt Discount – Otter Tail Corporation			4	4
Total Long-Term Debt			421,680	471,915
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, 2012			
$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	$	100.3375	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	521,974	571,448
Total Capitalization	$ 959,154	$ 1,058,863

See accompanying notes to consolidated financial statements.

Otter Tail Corporation
Notes to Consolidated Financial Statements
For the years ended December 31, 2012, 2011 and 2010

1. Summary of Significant Accounting Policies

Principles of Consolidation
The consolidated financial statements of Otter Tail Corporation and its wholly owned subsidiaries (the Company) include the accounts of the following segments: Electric, Manufacturing, 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 and revenues that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, OTP defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 4 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 $656,000 in 2012, $628,000 in 2011 and $76,000 in 2010. 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 2.98% in 2012, 2.94% in 2011 and 3.01% in 2010. 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. No interest was capitalized on nonelectric plant in 2012, 2011 or 2010. 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, 2012 and 2011 consolidated balance sheets:

(in thousands)	2012	2011
Big Stone Plant:		
Electric Plant in Service	$ 141,221	$ 143,993
Construction Work in Progress	22,335	2,674
Accumulated Depreciation	(80,588)	(87,669)
Net Plant	$ 82,968	$ 58,998
Coyote Station:		
Electric Plant in Service	$ 160,617	$ 156,213
Construction Work in Progress	578	1,533
Accumulated Depreciation	(93,564)	(97,090)
Net Plant	$ 67,631	$ 60,656

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.

Coyote Station Lignite Supply Agreement – Variable Interest Entity
In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton to be paid by the Coyote Station owners under the LSA will reflect the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining lignite coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE). Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. Although Coyote Station is the primary beneficiary of the VIE, no single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, have the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commences with the first delivery of coal to Coyote Station, scheduled for May 2016, by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through December 31, 2012 totaled $8.3 million.

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 idled this plant in the fourth quarter of 2011, as the plant had completed all of its then current tower orders.

In June 2012, the Company entered into a nonbinding letter of interest with Trinity Industries, Inc. (Trinity) to sell the fixed assets of DMI for $20 million, with the Company retaining DMI's net working capital—approximately $66 million on June 30, 2012. On September 6, 2012 the Company entered into definitive agreements with Trinity to sell the fixed assets of DMI for $20 million. The agreed on price for the fixed assets was an indicator of the fair value of the assets under level 2 of the ASC fair value hierarchy and an indication of a decrease in the market value of the assets being sold, which were significantly impacted by a decline in market conditions in the wind energy industry. DMI had no tower orders for 2013 due to the expected expiration, at the end of 2012, of the Federal Production Tax Credit (PTC) for investments in renewable energy resources. These factors resulted in DMI recording a fair value adjustment of its long-lived assets to the indicated market price of $20 million and an asset impairment charge of $45.6 million ($27.5 million net-of-tax benefits), or $0.76 per share, in June 2012 broken down as follows:

(in thousands)		
Long-Lived Assets (net of accumulated depreciation)	$	45,285
Goodwill		288
Total Asset Impairment Charges	$	45,573

The sale of the Fort Erie fixed assets closed on September 6, 2012, the West Fargo transaction closed on October 31, 2012 and the Tulsa transaction closed on November 30, 2012. With the sale of DMI's Tulsa assets DMI's operations under the Company ended and, accordingly, DMI's cash flows, results of operations, and any remaining assets and liabilities are reported under discontinued operations as of, and for all periods ending prior to, December 31, 2012.

Otter Tail Energy Services Company (OTESCO) recorded asset impairment charges of $0.4 million in 2012 and $0.5 million in 2011 related to wind farm development rights at its Sheridan Ridge and Stutsman County sites in North Dakota based on the fair value of these assets declining to $0 as of March 31, 2012.

On February 8, 2013 the Company closed on the sale of substantially all of the assets of ShoreMaster Inc. (ShoreMaster), subject to certain closing conditions. The Company recorded a $7.7 million ($4.6 million net-of-tax benefits), or $0.13 per share, asset impairment charge in December 2012 based on the indicated market value of ShoreMaster's assets broken down as follows:

(in thousands)	
Long-Lived Assets (net of accumulated depreciation)	$ 5,859
Inventory	782
Accrued Selling Costs	1,106
Total Impairment Charges	$ 7,747

As a result of the pending sale, ShoreMaster's assets are considered held for sale as of December 31, 2012 and, along with its liabilities, cash flows, and results of operations, are reported under discontinued operations as of, and for all periods ending prior to, December 31, 2012.

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. If we determine we would be able to realize our deferred income tax assets in the future in excess of their net recorded amount, we would make an adjustment to the deferred tax asset valuation allowance, which would reduce the provision for income taxes. 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, under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is recognized for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the fuel clause adjustment, for conservation program incentives and bonuses earned but not yet billed and for renewable resource 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.

Manufacturing operating revenues are recorded when products are shipped.

The companies in the Construction segment 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 costs incurred to total estimated costs on construction projects. Following are the percentages of the Company's consolidated revenues recorded under the percentage-of-completion method:

	2012	2011	2010
Percentage-of-Completion Revenues	17.3 %	22.0 %	18.6 %

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

(in thousands)	December 31, 2012	December 31, 2011
Costs Incurred on Uncompleted Contracts	$ 307,085	$ 321,346
Less Billings to Date	(321,388)	(340,418)
Plus Estimated Earnings Recognized	1,762	22,108
	$ (12,541)	$ 3,036

The following costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings are included in the Company's consolidated balance sheets.

(in thousands)	December 31, 2012	December 31, 2011
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 3,663	$ 12,211
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(16,204)	(9,175)
	$ (12,541)	$ 3,036

The Company has a standard quarterly Estimate at Completion process in which management reviews the progress and performance of the Company's contracts accounted for under percentage-of-completion accounting. As part of this process, management reviews include, but are not limited to, any outstanding key contract matters, progress towards completion and the related program schedule, identified risks and opportunities, and the related changes in estimates of revenues and costs. The risks and opportunities include management's judgment about the ability and cost to achieve the schedule, technical requirements and other contract requirements. Management must make assumptions regarding labor productivity and availability, the complexity of the work to be performed, the availability of materials, the length of time to complete the contract, and performance by subcontractors, among other variables. Based on this analysis, any adjustments to net sales, costs of sales, and the related impact to operating income are recorded as necessary in the period they become known. These adjustments may result from positive program performance and an increase in operating profit during the performance of individual contracts if management determines it will be successful in mitigating risks surrounding the technical, schedule, and cost aspects of those contracts or realizing related opportunities. Likewise, these adjustments may result in a decrease in operating profit if management determines it will not be successful in mitigating these risks or realizing related opportunities. Changes in estimates of net sales, costs of sales, and the related impact to operating income are recognized using a cumulative catch-up, which recognizes, in the current period, the cumulative effect of the changes on current and prior periods based on a contract's percent complete. A significant change in one or more of these estimates could affect the profitability of one or more of the Company's contracts. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized.

In 2012, Foley Company (Foley) experienced cost overruns in excess of estimated costs on several large projects. Estimated costs on certain projects in excess of previous period estimates resulted in pretax charges of $14.9 million in 2012 compared with $7.0 million in 2011. All of these projects were substantially completed as of December 31, 2012.

Plastics operating revenues are recorded when the product is shipped.

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, 2011	$	3,170
Provision for Warranties Used During the Year		3,240
Less Settlements Made During the Year		(1,342)
Decrease in Warranty Estimates for Prior Years		(41)
Warranty Reserve Balance, December 31, 2012	$	5,027

The warranty reserve balance as of December 31, 2012 relates entirely to products produced by DMI and ShoreMaster and is included in liabilities of discontinued operations. Expenses associated with remediation activities of DMI could be substantial. Although the assets of DMI and ShoreMaster have been sold and DMI’s and ShoreMaster’s operating results are reported under discontinued operations in the Company’s consolidated statements of income, the Company retains responsibility for warranty claims related to the products produced by DMI and ShoreMaster prior to the sales of these entities. For DMI’s wind towers, 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, 2012	December 31, 2011
Accounts Receivable Retained by Customers	$12,227	$13,075

Shipping and Handling Costs

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

Use of Estimates

The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. 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, 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, 2012 and 2011:

(in thousands)	December 31, 2012	December 31, 2011
Cost Method:		
Portion of IPH Sales Proceeds Held in Escrow Account1	$ 1,500	$ 3,001
Economic Development Loan Pools	255	320
Other	174	206
Equity Method:		
Affordable Housing and Other Partnerships	117	276
Marketable Securities Classified as Available-for-Sale	8,925	8,790
Total Investments	$ 10,971	$ 12,593
Less: IPH Escrow Funds Reported under Other Current Assets1	(1,500)	(1,500)
Investments	$ 9,471	$ 11,093

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 fair values on December 31, 2012. 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.

Fair values for OTP’s forward energy contracts with delivery points that are not at an active trading hub included in Level 3 of the fair value hierarchy in the table below as of December 31, 2012, are based on prices indexed to observable prices at an active trading hub. The range for Level 3 forward electric inputs was $16 to $48 per megawatt-hour. The weighted average price was $35 per megawatt-hour. The level of deviation in the indexed prices of these contracts at their point of physical delivery from the observable prices for similar contracts at an active trading hub resulted in the contracts that were outstanding at both December 31, 2011 and December 31, 2012 being moved from Level 2 to Level 3 of the fair value hierarchy in 2012.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the year ended December 31, 2012, the first year the Company's forward energy contracts were classified as Level 3 in the fair value hierarchy:

(in thousands)		Year ended December 31, 2012	
Forward Energy Contracts - Fair Values Beginning of Year	$	--	
Transfers into Level 3 from Level 2		(15,884	)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods		5,135	
Changes in Fair Value of Contracts Entered into in Prior Periods		(4,001	)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period		(14,750	)
Net Losses Recognized as Regulatory Assets on contract entered into in 2012		(3,032	)
Forward Energy Contracts - Net Derivative Liability Fair Values End of Year	$	(17,782	)

All Level 3 forward energy contracts in the table below are related to power purchase contracts where OTP intends to take physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts the costs incurred will be recovered in base rates and through fuel clause adjustments. Any derivative assets or liabilities and related gains or losses recorded as a result of the fair valuation of these power purchase contracts will not be realized and are 100% offset by regulatory liabilities and assets related to fuel clause adjustment treatment of fuel costs. Therefore, the net impact of any recorded fair valuation gains or losses related to these contracts on the Company's consolidated net income is $0 and the net income impact of any future fair valuation adjustments of these contracts will be $0. When energy is delivered under these contracts, they will be settled at the original contract price and any fair valuation gains or losses and related derivative assets or liabilities recorded over the life of the contracts will be reversed along with any offsetting regulatory liabilities or assets. Because of regulatory accounting treatment, any price volatility related to the fair valuation of these contracts had no impact on the Company's reported consolidated net income for 2012, 2011 or 2010.

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:

2012 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$292	$210
Forward Gasoline Purchase Contracts		136	
Money Market Fund - Escrow Account IPH Sale	1,500		
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		7,620	
U.S. Government Debt Securities – Held by Captive Insurance Company		1,305	
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	357		
Equity Securities - Nonqualified Retirement Savings Plan	125		
Total Assets	$2,092	$9,353	$210
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$242	$17,992
Total Liabilities	$--	$242	$17,992

In 2012, the Company's investments in forward gasoline contracts and U.S. government debt securities were moved to level 2 of the fair value hierarchy.

2011 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets – Other:			
Forward Energy Contracts	$--	$3,803	
Forward Gasoline Purchase Contracts	9		
Money Market Fund - Escrow Account IPH Sale	1,500		
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	110		
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		8,083	
U.S. Government Debt Securities – Held by Captive Insurance Company	707		
Money Market Fund - Escrow Account IPH Sale	1,501		
Other Assets:			
Money Market and Mutual Funds - Nonqualified Retirement Savings Plan	254		
Total Assets	$4,081	$11,886	
Liabilities:			
Derivative Liabilities - Forward Energy Contracts	$--	$18,770	
Total Liabilities	$--	$18,770	

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, 2012	December 31, 2011
Finished Goods	$ 21,893	$ 18,478
Work in Process	8,800	10,470
Raw Material, Fuel and Supplies	38,643	39,795
Total Inventories	$ 69,336	$ 68,743

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.

In the fourth quarter of 2012 the Company sold Moorhead Electric, Inc. (MEI), a subsidiary company that provided electrical contracting services. In connection with this sale, the Company disposed of $147,000 in goodwill associated with the purchase of MEI in 1992.

The following tables summarize changes to goodwill by business segment during 2012 and 2011:

(in thousands)	Gross Balance	Accumulated Impairments	Balance (net of impairments)	Adjustments to Goodwill	Balance (net of impairments)

	December 31, 2011		December 31, 2011	in 2012	December 31, 2012
Electric	$240	$ (240)	$ --	$ --	$ --
Manufacturing	24,445	(12,259)	12,186	--	12,186
Construction	7,630	--	7,630	(147)	7,483
Plastics	19,302	--	19,302	--	19,302
Total	$51,617	$ (12,499)	$ 39,118	$ (147)	$ 38,971

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(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)	$ --	$ --	$ --
Manufacturing	24,445	(12,259)	12,186	--	12,186
Construction	7,630	--	7,630	--	7,630
Plastics	19,302	--	19,302	--	19,302
Total	$ 51,617	$ (12,499)	$ 39,118	$ --	$ 39,118

Other Intangible Assets

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

2012 (in thousands)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortizable Intangible Assets:				
Customer Relationships	$ 16,811	$ 4,085	$ 12,726	15 – 25 years
Other Intangible Assets Including Contracts	1,092	613	479	5 – 30 years
Total	$ 17,903	$ 4,698	$ 13,205	
Indefinite-Lived Intangible Assets:				
Trade Name	$ 1,100	--	$ 1,100	
2011 (in thousands)				
Amortizable 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	1,092	485	607	5 – 30 years
Total	$ 18,616	$ 4,430	$ 14,186	
Indefinite-Lived Intangible Assets:				
Trade Name	$ 1,100	--	$ 1,100	

The amortization expense for these intangible assets was:

(in thousands)	2012	2011	2010
Amortization Expense – Intangible Assets	$981	$956	$895

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

(in thousands)	2013	2014	2015	2016	2017
Estimated Amortization Expense – Intangible Assets	$977	$977	$977	$945	$849

Supplemental Disclosures of Cash Flow Information

	As of December, 31	
(in thousands)	2012	2011
Noncash Investing Activities:		

Accounts Payable Outstanding Related to Capital Additions1	$ 9,967	$ 20,521

1Amounts are included in cash used for capital expenditures in subsequent periods when payables are settled.

(in thousands)	2012	2011	2010
Cash Paid During the Year for:			
Interest (net of amount capitalized)	$ 30,741	$ 34,434	$ 33,094
Income Tax Refunds	$ (353)	$ (257)	$ (54,346)

Reclassifications and Changes to Presentation

The Company’s consolidated balance sheet as of December 31, 2011 and consolidated income statement and consolidated statement of cash flows for the years ended December 31, 2011 and 2010 reflect the reclassifications of the assets and liabilities, operating results and cash flows of DMI and ShoreMaster to discontinued operations as a result of the sale of DMI’s fixed assets in 2012 and the sale of ShoreMaster on February 8, 2013. As of December 31, 2012 the Company met the criteria of assets held for sale under ASC 360-10-45 for the ShoreMaster transaction and appropriately classified the assets as held for sale on December 31, 2012. Accordingly, ShoreMaster’s activities were required to be reported in discontinued operations as required under ASC 205-20-45. 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, 2011 and 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

ASU 2013-02

In February 2013, the FASB issued ASU 2013-02, “Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income,” which requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, entities are required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail on these amounts. This ASU is effective prospectively for reporting periods beginning after December 15, 2012. The Company is currently evaluating the impact of adopting this guidance.

2. Business Combinations, Dispositions and Segment Information

The Company acquired no new businesses in 2012, 2011 or 2010 and disposed of no businesses in 2010.

In 2012 and 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 or was in the process of selling several of its holdings. On December 31, 2012 the Company was in negotiations to sell the assets of ShoreMaster, its waterfront equipment manufacturer, which was included in its Manufacturing segment. ShoreMaster’s assets met the criteria to be classified as held for sale and reported in discontinued operations on December 31, 2012. The sale of substantially all of ShoreMaster’s assets closed on February 8, 2013. On November 30, 2012 the Company completed the sale of the fixed assets of DMI, its wind tower manufacturing company, eliminating its Wind Energy segment. On February 29, 2012 the Company completed the sale of DMS Health

Technologies, Inc. (DMS), its health services company, eliminating its Health Services segment. On January 18, 2012, the Company sold the assets of Aviva Sports, Inc. (Aviva), a wholly owned subsidiary of ShoreMaster that sold various recreational products. In 2011, the Company sold IPH, its food ingredient processing business, eliminating its Food Ingredient Processing segment, and E.W. Wylie (Wylie), its trucking company, which was included in its Wind Energy segment.

The results of operations of ShoreMaster including Aviva, DMI, DMS, Wylie and IPH are reported as discontinued operations in the Company's consolidated financial statements as of and for the years ended December 31, 2012, 2011 and 2010, 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, 2012 and 2013 dispositions, the Company's business structure now includes the following four segments: Electric, 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.

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

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

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.

No single customer accounted for over 10% of the Company's consolidated revenues in 2012, 2011 or 2010. All of the Company's long-lived assets are within the United States.

Percent of Sales Revenue by Country for the Year Ended December 31:	2012	2011	2010
United States of America	97.7%	98.1%	99.0%
Canada	1.1%	1.4%	0.8%
All Other Countries	1.2%	0.5%	0.2%

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Substantially all the revenues reported below by segment are from sales to external customers, except for immaterial amounts reported in intersegment eliminations, which are insignificant in total and by segment. Information on continuing operations for the business segments for 2012, 2011 and 2010, which now excludes Wind Energy due to the sale of DMI and its inclusion in discontinued operations, and includes restated amounts for the Manufacturing segment due to the sale of ShoreMaster and its inclusion in discontinued operations, is presented in the following table:

(in thousands)	2012			2011			2010		
Operating Revenue									
Electric	$	350,765		$	342,727		$	344,379	
Manufacturing		208,965			189,459			143,072	
Construction		149,092			184,657			134,222	
Plastics		150,517			123,669			96,945	
Intersegment Eliminations		(100	)		(343	)		(721	)
Total	$	859,239		$	840,169		$	717,897	
Depreciation and Amortization									
Electric	$	42,051		$	40,283		$	40,241	
Manufacturing		12,208			12,116			11,430	
Construction		1,906			2,009			2,023	
Plastics		3,118			3,377			3,430	
Corporate		481			550			523	
Total	$	59,764		$	58,335		$	57,647	
Interest Charges									
Electric	$	19,049		$	19,643		$	20,949	
Manufacturing		3,557			3,727			3,625	
Construction		1,039			947			671	
Plastics		2,519			1,525			1,560	
Corporate and Intersegment Eliminations		5,741			9,787			10,043	
Total	$	31,905		$	35,629		$	36,848	
Income (Loss) Before Income Taxes									
Electric	$	44,203		$	45,569		$	44,505	
Manufacturing		17,630			12,191			7,548	
Construction		(13,145	)		(3,688	)		(1,115	)
Plastics		23,506			9,464			4,007	
Corporate		(31,093	)		(24,505	)		(25,434	)
Total	$	41,101		$	39,031		$	29,511	
Earnings (Loss) Available for Common Shares									
Electric	$	38,341		$	38,886		$	34,557	
Manufacturing		10,676			8,229			5,115	
Construction		(7,689	)		(2,204	)		(646	)
Plastics		14,113			5,811			2,515	
Corporate		(17,209	)		(16,548	)		(15,996	)
Discontinued Operations		(44,241	)		(48,475	)		(27,722	)
Total	$	(6,009	)	$	(14,301	)	$	(2,177	)
Capital Expenditures									
Electric	$	101,919		$	49,707		$	43,121	
Manufacturing		9,311			10,546			6,159	

Construction		1,576		2,645		5,490
Plastics		2,819		2,414		2,671
Corporate		137		2,048		823
Total	$	115,762	$	67,360	$	58,264
Identifiable Assets						
Electric	$	1,226,145	$	1,170,449	$	1,106,261
Manufacturing		114,933		124,872		112,295
Construction		50,696		69,453		60,978
Plastics		78,855		72,200		73,508
Corporate		112,616		53,619		43,102
Assets of Discontinued Operations		19,092		209,929		374,411
Total	$	1,602,337	$	1,700,522	$	1,770,555

Revised Segments Information by Quarter (not audited)

The following table provides revised segment information based on the Company's continuing operations as of December 31, 2012, similar to the tabular information provided in note 2 to financial statements in the Company's quarterly reports on Form 10-Q.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands)	2012	2011	2012	2011	2012	2011	2012	2011
Operating Revenue								
Electric	$90,003	$91,596	$78,963	$78,031	$88,564	$85,172	$93,235	$87,928
Manufacturing	59,434	46,953	53,039	45,178	46,618	47,323	49,874	50,005
Construction	35,617	37,515	37,934	49,133	37,931	53,247	37,610	44,762
Plastics	34,875	18,478	41,490	44,373	42,217	36,231	31,935	24,587
Corporate and Intersegment Eliminations	(39)	(261)	(25)	(38)	(14)	(27)	(22)	(17)
Total	$219,890	$194,281	$211,401	$216,677	$215,316	$221,946	$212,632	$207,265
Interest Charges								
Electric	$4,851	$5,088	$4,762	$4,990	$4,880	$4,796	$4,556	$4,769
Manufacturing	915	903	917	941	891	952	834	931
Construction	253	220	310	227	305	251	171	249
Plastics	346	363	346	402	342	411	1,485	349
Corporate and Intersegment Eliminations	2,229	2,769	2,137	2,558	1,486	2,268	(111)	2,192
Total	$8,594	$9,343	$8,472	$9,118	$7,904	$8,678	$6,935	$8,490
Income Tax Expense (Benefit)								
Electric	$1,622	$2,600	$(800)	$8	$2,995	$3,364	$2,045	$711
Manufacturing	2,324	1,579	1,674	1,215	1,288	938	1,668	230
Construction	(2,776)	(210)	(1,164)	130	(879)	(115)	(637)	(1,289)
Plastics	2,175	(241)	2,722	2,144	2,216	1,295	2,280	455
Corporate	(2,877)	(1,902)	(1,915)	(2,617)	(6,405)	(3,373)	(3,423)	(801)
Total	$468	$1,826	$517	$880	$(785)	$2,109	$1,933	$(694)
Earnings (Loss) Available for Common Shares								
Electric	$11,016	$11,142	$5,191	$7,386	$10,206	$10,900	$11,928	$9,458
Manufacturing	3,465	2,356	2,501	2,179	1,914	1,571	2,796	2,123
Construction	(4,171)	(325)	(1,756)	184	(1,325)	(179)	(437)	(1,884)
Plastics	3,253	(374)	4,067	3,312	3,309	1,970	3,484	903
Corporate	(3,572)	(2,964)	(3,286)	(3,437)	(9,486)	(5,355)	(865)	(4,792)
	(2,932)	(4,323)	(24,257)	8,698	(2,928)	(2,723)	(14,124)	(50,127)

Discontinued Operations								
Total	$7,059	$5,512	$(17,540)	$18,322	$1,690	$6,184	$2,782	$(44,319)
Identifiable Assets								
Electric	$1,167,688	$1,094,549	$1,168,902	$1,092,111	$1,179,472	$1,101,146	$1,226,145	$1,170,449
Manufacturing	133,988	120,161	127,055	125,967	125,747	124,414	114,933	124,872
Construction	67,288	64,500	68,407	65,351	67,342	74,639	50,696	69,453
Plastics	87,066	76,993	87,747	94,035	86,445	84,463	78,855	72,200
Corporate	42,292	46,947	39,222	41,380	38,612	57,262	112,616	53,619
Discontinued Operations	180,796	393,831	143,067	289,303	72,308	270,060	19,092	209,929
Total	$1,679,118	$1,796,981	$1,634,400	$1,708,147	$1,569,926	$1,711,984	$1,602,337	$1,700,522

3. Rate and Regulatory Matters

Minnesota

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

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.

The MPUC issued an order on January 12, 2010 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. The MPUC approved OTP's petition for a 2010 MNRRA in the third quarter of 2010 with implementation effective September 1, 2010. The 2010 MNRRA was in place from September 1, 2010 through September 30, 2011 with a recovery of $17.0 million.

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 the MNRRA regulatory asset. OTP has a regulatory asset of $0.9 million for amounts eligible for recovery through the MNRRA rider that have not been billed to Minnesota customers as of December 31, 2012. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. The filing, which is still under review, included a request to extend the period of the new rate for 18 months, which would reduce the current balance of unrecovered costs to zero. However, OTP now estimates the remaining unrecovered costs will collected by the end of May 2013, so OTP is planning to make a supplemental filing to request that the current rate be retained until the remaining balance is recovered and that the MNRRA then be suspended.

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 exempt from the requirement to obtain a Minnesota CON. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

OTP requested recovery of its transmission investments being recovered through its Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs 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. The update to OTP's Minnesota TCR rider, approved by the MPUC on March 26, 2012, went into effect April 1, 2012.

In this TCR rider update, the MPUC addressed how to handle utility investments in transmission facilities that qualify for regional cost allocation under the MISO tariff. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from the other MISO utilities. On March 26, 2012 the MPUC approved an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made with an offsetting credit for revenues received from other MISO utilities under the MISO tariff.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On August 22, 2012 the Minnesota Department of Commerce (MNDOC) filed comments and on August 24, 2012 the Minnesota Office of the Attorney General (MNOAG) filed comments. OTP filed reply comments on September 25, 2012 and supplemental comments on January 8, 2013 describing an agreement reached between OTP, the MNDOC and the MNOAG, to find eligible 3 of the 12 projects. MPUC approval of that agreement is pending. If approval is obtained to include additional projects in the rider, investment in the approved projects will be included in the next annual Minnesota TCR rider rate update filings and recovery of the investment will begin through the TCR rider rates if subsequently approved by the MPUC. Updated costs associated with existing projects within the Minnesota TCR rider will also be included in the next annual rider rate update filing. OTP has a regulatory liability of $0.5 million as of December 31, 2012 for amounts billed to Minnesota customers that are subject to refund through the Minnesota TCR rider.

Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. The Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal.

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

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 written order was issued by the MPUC on January 11, 2012 approving the recovery of $3.5 million for the 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment (CCRA) increased from 3.0% to 3.8% for all Minnesota retail electric customers.

OTP recognized $2.2 million in MNCIP financial incentives in 2011 relating to 2011 program results. On March 30, 2012 OTP submitted its annual 2011 financial incentive filing request for $2.6 million and recognized an additional $0.4 million of incentive related to 2011 in 2012. In December 2012, the MPUC approved the recovery of $2.6

million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer's bill to an amount per kwh consumed. The written order was issued on December 10, 2012. On January 1, 2013 OTP's MNCIP surcharge decreased from 3.8% of the customer's bill to $0.00142 per kwh , which equates to approximately 1.9% of a customer's bill . The per-kwh cost allocation method is the principle method approved by the MPUC for other electric utilities in Minnesota. OTP recognized $2.6 million of MNCIP financial incentives in 2012 relating to 2012 program results.

OTP has a regulatory asset of $6.1 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, 2012. OTP's Minnesota conservation recoverable costs and incentives totaled $7.8 million in 2012, $8.0 million in 2011 and $8.6 million in 2010.

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 North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed. OTP 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 costs and returns on investments in renewable energy facilities under the NDRRA 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.

The 2010 NDRRA was in place for the period of September 1, 2010 through March 31, 2012 with a recovery of $15.6 million. On December 29, 2011 OTP submitted its annual update to the renewable rider with an April 1, 2012 effective date, which was approved by the NDPSC on March 21, 2012. The 2011 NDRRA has an expected recovery of $10.1 million over the period April 1, 2012 through March 31, 2013. OTP has a regulatory asset of $1.6 million for amounts eligible for recovery through the NDRRA rider that have not been billed to North Dakota customers as of December 31, 2012.

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 filed a request for an initial North Dakota TCR rider with the NDPSC on April 29, 2011, which was approved by the NDPSC on April 25, 2012 to go into effect May 1, 2012. On August

31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider, which the NDPSC approved on December 12, 2012 to go into effect January 1, 2013. OTP has a regulatory asset of $0.1 million for amounts eligible for recovery through the North Dakota TCR rider that have not been billed to North Dakota customers as of December 31, 2012.

South Dakota

2010 General Rate Case Filing—On August 20, 2010 OTP filed a general rate case with the South Dakota Public Utilities Commission (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 billed $570,000 to South Dakota customers under the TCR rider from December 1, 2011 through December 31, 2012 and had a regulatory asset of $2,000 for amounts eligible for recovery through the South Dakota TCR rider that had not been billed to South Dakota customers as of December 31, 2012. On September 4, 2012 OTP filed its annual update to the South Dakota TCR rider rate. The request is currently under review by the SDPUC.

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

On June 16, 2010 OTP filed a request with the SDPUC for approval of updates to 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, or $84,000.

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 (MISO 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% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP’s control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects 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 the FERC reaffirmed the MVP cost allocation on rehearing. The MVP cost allocation is currently being challenged at the United States Court of Appeals, Seventh Circuit.

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

The Big Stone South – Brookings Project—OTP is jointly developing this project with Xcel Energy. MISO approved this project as an MVP under the MISO Tariff in December 2011. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. A portion of this line is anticipated to use previously obtained Big Stone II transmission route permits and easements and is expected to be in service in 2017. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP. In December 2012, a request was filed with the SDPUC for recertification of a portion of the line route that was approved as part of the Big Stone II transmission development. OTP and Xcel Energy expect to make a joint route permit filing in the second quarter of 2013 for the remaining portion of the project.

The Ellendale – Big Stone South Project—OTP is jointly developing this project with Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. This project will require regulatory approval from both the SDPUC and the NDPSC. Route permits are expected to be filed with the respective commissions in the third quarter of 2013.

Capacity Expansion 2020 (CapX2020)

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

The Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project. The Monticello to St. Cloud portion of the Fargo Project was placed into service on December 21, 2011. Completion of all phases of the Fargo Project is scheduled for the first quarter of 2015.

The Brookings Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Brookings Project. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project will be placed in 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.

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

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 March 29, 2012 the EPA took final action to approve South Dakota's Regional Haze State Implementation Plan (SIP), finding that South Dakota's SIP submittal met all applicable regional haze regulations. The EPA's final approval of the SIP was effective on May 29, 2012.

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 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.

An application for an ADP filed by OTP with the NDPSC on May 20, 2011 was approved on May 9, 2012.

On March 30, 2012 OTP requested approval from the SDPUC for an ECRR to recover costs associated with the Big Stone Plant AQCS, with a proposed effective date of October 1, 2012. Information requests for this filing continue and OTP is currently awaiting SDPUC action. This rider is designed to recover the revenue requirements plus carrying charges of the Big Stone AQCS project while under construction as well as after completion of the project until placed into base rates through the filing of a rate case. For the initial period of October 1, 2012 through September 30, 2013, OTP is requesting revenue requirement recovery on expenditures incurred for the Big Stone Plant AQCS. The request is currently under review by the SDPUC.

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. 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 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 is including 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 which began on August 1, 2010.

The North Dakota 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. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP.

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 regulatory assets reflect incurred costs eligible for recovery in future periods on which the Company will not earn a rate of return: Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits, the Accumulated ARO Accretion/Depreciation Adjustment, Debt Reacquisition Premiums, Big Stone II Unrecovered Project Costs – Minnesota, Deferred Income Taxes, the MISO Schedule 26 Transmission Cost Recovery Rider True-up, Big Stone II Unrecovered Project Costs – North Dakota, General Rate Case Recoverable Expenses and Deferred Holding Company Formation Costs. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following regulatory assets represent amounts eligible for recovery under alternative revenue programs or on which the Company earns an incentive or rate of return: Conservation Improvement Program Costs and Incentives, North Dakota Renewable Resource Rider Accrued Revenues, Minnesota Renewable Resource Rider Accrued Revenues, Big Stone II Unrecovered Project Costs – South Dakota, North Dakota Transmission Rider Accrued Revenues and South Dakota Transmission Rider Accrued Revenue The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

	December 31, 2012			Remaining Recovery/
(in thousands)	Current	Long-Term	Total	Refund Period
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$8,411	$109,538	$117,949	see note
Deferred Marked-to-Market Losses	7,949	10,050	17,999	72 months
Conservation Improvement Program Costs and Incentives	3,707	2,560	6,267	18 months
Accumulated ARO Accretion/Depreciation Adjustment	--	4,137	4,137	asset lives
Debt Reacquisition Premiums	268	1,978	2,246	237 months
Big Stone II Unrecovered Project Costs – Minnesota	526	1,618	2,144	45 months
Recoverable Fuel and Purchased Power Costs	1,737	--	1,737	12 months
Deferred Income Taxes	--	1,691	1,691	asset lives
North Dakota Renewable Resource Rider Accrued Revenues	532	1,087	1,619	15 months
MISO Schedule 26 Transmission Cost Recovery Rider True-up	--	1,352	1,352	see note
Minnesota Renewable Resource Rider Accrued Revenues	915	--	915	5 months
Big Stone II Unrecovered Project Costs – North Dakota	908	--	908	7 months
Big Stone II Unrecovered Project Costs – South Dakota	100	711	811	97 months
General Rate Case Recoverable Expenses	279	6	285	13 months
North Dakota Transmission Rider Accrued Revenues	110	--	110	12 months
Deferred Holding Company Formation Costs	55	27	82	18 months
South Dakota Transmission Rider Accrued Revenue	2	--	2	12 months
Total Regulatory Assets	$25,499	$134,755	$160,254	
Regulatory Liabilities:				

Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$--	$65,960	$65,960	asset lives
Deferred Income Taxes	--	2,553	2,553	asset lives
Minnesota Transmission Rider Accrued Refund	489	--	489	12 months
Deferred Marked-to-Market Gains	8	210	218	68 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	6	112	118	252 months
South Dakota – Nonasset-Based Margin Sharing Excess	56	--	56	12 months
Total Regulatory Liabilities	$559	$68,835	$69,394	
Net Regulatory Asset Position	$24,940	$65,920	$90,860	

(in thousands)	December 31, 2011 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	$6,304	$96,074	$102,378	see notes
Deferred Marked-to-Market Losses	5,208	10,749	15,957	44 months
Conservation Improvement Program Costs and Incentives	5,234	2,208	7,442	18 months
Recoverable Fuel and Purchased Power Costs	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	

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, 2012 are related to forward purchases of energy scheduled for delivery through December 2018.

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

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

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 237 months.

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.

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.

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, 2012.

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. The December 31, 2012 balance will be amortized on a straight-line basis over a period of 12 months beginning in January 2014.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 through December 31, 2012 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of December 31, 2012.

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.

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 a ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted.

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

North Dakota Transmission Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities and net operating costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2012.

The South Dakota Transmission Rider Accrued Revenues relate to revenues billed for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers net of transmission revenues that are refundable to South Dakota customers as of December 31, 2012.

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

The Minnesota Transmission Rider Accrued Refund relates to revenues billed for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers net of transmission revenues that are refundable to Minnesota customers as of December 31, 2012.

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.

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, 2012 OTP had recognized, on a pretax basis, $49,000 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 and level 3 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 Independent Transmission System Operator markets, broken down as follows for the years ended December 31:

(in thousands)	2012	2011	2010
Wholesale Sales - Company-Owned Generation	$12,951	$14,518	$20,053
Revenue from Settled Contracts at Market Prices	160,987	168,313	147,003
Market Cost of Settled Contracts	(159,500)	(166,920)	(145,994)
Net Margins on Settled Contracts at Market	1,487	1,393	1,009
Marked-to-Market Gains on Settled Contracts	7,864	10,208	18,901
Marked-to-Market Losses on Settled Contracts	(7,974)	(10,176)	(17,529)
Net Marked-to-Market (Losses) Gains on Settled Contracts	(110)	32	1,372
Unrealized Marked-to-Market Gains on Open Contracts	284	3,707	6,700
Unrealized Marked-to-Market Losses on Open Contracts	(235)	(2,813)	(5,937)
Net Unrealized Marked-to-Market Gains on Open Contracts	49	894	763
Wholesale Electric Revenue	$14,377	$16,837	$23,197

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, 2012 and December 31, 2011, and the change in the Company's consolidated balance sheet position from December 31, 2011 to December 31, 2012 and December 31, 2010 to December 31, 2011:

(in thousands)	December 31, 2012	December 31, 2011
Other Current Asset – Marked-to-Market Gain	$ 502	$ 3,803
Regulatory Asset – Current Deferred Marked-to-Market Loss	7,949	5,208
Regulatory Asset – Long-Term Deferred Marked-to-Market Loss	10,050	10,749
Total Assets	18,501	19,760
Current Liability – Marked-to-Market Loss	(18,234)	(18,770)
Regulatory Liability – Current Deferred Marked-to-Market Gain	(8)	(96)
Regulatory Liability – Long-Term Deferred Marked-to-Market Gain	(210)	--
Total Liabilities	(18,452)	(18,866)
Net Fair Value of Marked-to-Market Energy Contracts	$ 49	$ 894

(in thousands)	Year ended December 31, 2012	Year ended December 31, 2011
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	$ 894	$ 763
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(861)	(356)
Changes in Fair Value of Contracts Entered into in Prior Periods	(33)	(86)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	321
Changes in Fair Value of Contracts Entered into in Current Period	49	573
Cumulative Fair Value Adjustments Included in Earnings - End of Period	$ 49	$ 894

The $49,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2012 is expected to be realized on settlement in the first quarter of 2013.

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, 2012 and December 31, 2011:

	December 31, 2012		December 31, 2011	
(in thousands)	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	$580	6	$1,677	10
Net Credit Risk to Single Largest Counterparty	$285		$737	

OTP had a net credit risk exposure to five counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. OTP had no exposure at December 31, 2012 or 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 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, 2012 and December 31, 2011:

Current Liability – Marked-to-Market Loss (in thousands)	December 31, 2012	December 31, 2011
Loss Contracts Covered by Deposited Funds or Letters of Credit	$ 2,176	$ 3,423
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade1	16,058	15,347
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	--
Total Current Liability – Marked-to-Market Loss	$ 18,234	$ 18,770

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	$	16,058	$	15,347
Offsetting Gains with Counterparties under Master Netting Agreements		(416)		(3,471)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	$	15,642	$	11,876

6. Common Shares and Earnings Per Share

On May 11, 2012 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, debt or other securities described in the shelf registration statement, including common shares of the Company.

Common Share Distribution Agreement
On May 14, 2012 the Company entered into a Distribution Agreement (the Agreement) with J.P. Morgan Securities (JPMS) under which 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 2012.

Following is a reconciliation of the Company's common shares outstanding from December 31, 2011 through December 31, 2012:

Common Shares Outstanding, December 31, 2011	36,101,695
Issuances:	
Restricted Stock Issued to Employees	26,120
Restricted Stock Issued to Nonemployee Directors	24,000
Conversion of Restricted Stock Units Vested	23,450
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(5,072)
Forfeiture of Unvested Restricted Stock	(1,825)
Common Shares Outstanding, December 31, 2012	36,168,368

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 957,359 were still available as of December 31, 2012 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. On April 16, 2012, the Company's shareholders approved an amendment to the Purchase Plan, increasing the number of shares available under the Purchase Plan from 900,000 common shares to 1,400,000 common shares and making certain other changes to the terms of the Purchase Plan. Of the 1,400,000 common shares authorized to be issued under the Purchase Plan, 522,227 were available for purchase as of December 31, 2012. 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, 60,439 common shares were purchased in the open market in 2012, 78,537 common shares were purchased in the open market in 2011 and 82,857 common shares were purchased in the open market in 2010. The shares to be purchased by employees participating in the Purchase Plan were not material to the calculation of diluted earnings per share during the investment period.

Dividend Reinvestment and Share Purchase Plan

On May 11, 2012 the Company filed a shelf registration statement with the SEC for the issuance of up to 1,500,000 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. In 2012 common shares were purchased in the open market to provide shares for the Plan. In 2010 and 2011 common shares were purchased in the open market to provide shares for the Plan under a prior shelf registration statement that expired on December 1, 2011.

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per share is earnings available for common shares with no adjustments in 2012, 2011 or 2010. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company's directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting outstanding shares for the following: (1) all potentially dilutive stock options, (2) underlying shares related to nonvested restricted stock units granted to employees, (3) nonvested restricted shares, (4) shares expected to be awarded for stock performance awards granted to executive officers, and (5) shares expected to be issued under the deferred compensation program for directors. The adjustments to the denominators used to calculate basic and diluted earnings per share resulted in no differences greater than $0.01 between basic and diluted earnings per share in total or from continuing or discontinued operations in each of the years ended December 31, 2012, 2011 and 2010.

The following outstanding stock options with exercise prices greater than the average market price of the underlying shares were excluded from the calculation of diluted earnings per share for the years ended December 31, 2012, 2011 and 2010:

Year	Options Outstanding	Range of Exercise Prices
2012	92,497	$24.93 – $27.245
2011	156,397	$24.93 – $31.34
2010	383,460	$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 $179,000 in 2012, $257,000 in 2011 and $277,000 in 2010. 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, 2012:

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

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Presented below is a summary of the stock options activity:

Stock Option Activity	2012 Options	2012 Average Exercise Price	2011 Options	2011 Average Exercise Price	2010 Options	2010 Average Exercise Price
Outstanding, Beginning of Year	156,397	$28.53	383,460	$27.28	444,810	$26.82
Granted	--	--	--	--	--	--
Exercised	--	--	--	--	27,800	19.75
Forfeited or Expired	63,900	31.34	227,063	26.43	33,550	27.38
Outstanding, End of Year	92,497	26.59	156,397	28.53	383,460	27.28
Exercisable, End of Year	92,497	26.59	156,397	28.53	383,460	27.28
Cash Received for Options Exercised		--		--		$549,000
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 16, 2012 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 2013 through 2016 and are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreement. The grant date fair value of each share of restricted stock was $21.32 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	2012 Shares	2012 Weighted Average Grant-Date Fair Value	2011 Shares	2011 Weighted Average Grant-Date Fair Value	2010 Shares	2010 Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	54,250	$23.26	59,725	$24.95	54,300	$27.81
Granted	24,000	21.32	24,000	22.51	24,800	21.835
Vested	21,350	24.86	29,475	26.07	19,375	28.98
Forfeited	--		--		--	
Nonvested, End of Year	56,900	21.84	54,250	23.26	59,725	24.95
Compensation Expense Recognized		$552,000		$740,000		$595,000
Fair Value of Shares Vested in Year		531,000		768,000		561,000

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 16, 2012 the Company's Board of Directors granted 24,500 shares of restricted stock to the Company's executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2013 through 2016 and are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreement. The grant date fair value of each share of restricted stock was $21.32 per share, the average market price on the date of grant.

On October 1, 2012 the Company's Board of Directors granted 1,620 shares of restricted stock to the Company's Vice President of Human Resources under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2013 through 2016 and are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreement. The grant date fair value of the award was $23.93 per share, the average market price on the date of the grant.

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

Employees' Restricted Stock Awards	2012		2011		2010	
	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	34,868	$22.86	66,161	$24.79	50,478	$28.31
Granted	26,120	21.48	24,600	22.51	31,600	21.835
Awards Vested	11,518	24.14	55,893	25.00	15,917	29.76
Forfeited	1,825	22.20	--		--	
Nonvested, End of Year	47,645	21.82	34,868	22.86	66,161	24.79
Compensation Expense Recognized		$325,000		$832,000		$914,000
Fair Value of Awards Vested		278,000		1,397,000		474,000

Restricted Stock Units Granted to Employees

On April 16, 2012 the Company's Board of Directors granted 12,800 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2016, the date the units vest. The grant date fair value of each restricted stock unit was $17.14 per share based on the market value of the Company's common stock on April 16, 2012, discounted for the value of the dividend exclusion over the four-year vesting period.

On October 1, 2012 the Company's Board of Director's granted 3,000 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2016, the date the units vest. The grant date fair value of each restricted stock unit was $19.87 per share based on the market value of the Company's common stock on October 1, 2012, discounted for the fair value of the dividend exclusion over the vesting period. The weighted average contractual term of stock units outstanding as of December 31, 2012 is 2.5 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	2012		2011		2010	
	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	73,815	$20.95	79,315	$23.55	92,670	$25.42
Granted	15,800	17.66	19,800	18.03	26,180	17.76
Vested	20,750	27.13	20,025	27.94	18,965	23.93
Forfeited	8,200	19.97	5,275	22.56	20,570	25.55
Nonvested, End of Year	60,665	18.11	73,815	20.95	79,315	23.55
Compensation Expense Recognized		$256,000		$349,000		$250,000
Fair Value of Units Converted in Year		563,000		559,000		454,000

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. The terms of the outstanding awards dictate that these awards be classified and accounted for as liability awards, in accordance with the requirements of ASC 718, with compensation 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 16, 2012 the Company’s Board of Directors granted performance share awards to the Company’s executive officers under the Incentive Plan for the 2012-2014 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	Grant Date Fair Value	Expense Recognized in the Year Ended December 31, 2012	2011	2010	Shares Awarded
2012-2014	161,600	121,539	$21.75	1,001,000	$--	$--	--
2011-2013	97,200	15,435	$23.61	254,000	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)	64,500
2008-2010	114,800	70,843	$37.59	--	--	888,000	18,600
Total				$1,255,000	$1,871,000	$1,223,000	158,700

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, 2009-2011 and 2010-2012 total shareholder return rankings resulted in no incentive share awards for the Company's active plan participants for the 2008-2010, 2009-2011 and 2010-2012 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 $845,000 of 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, 2012 the total remaining unrecognized amount of compensation expense related to stock-based compensation for all of the Company's stock-based payment programs was approximately $4.0 million (before income taxes), which will be amortized over a weighted-average period of 2.2 years.

8. Retained Earnings and Dividend 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, 2012.

The Company is a holding company with no significant operations of its own. The primary source of funds for payments of dividends to the Company's shareholders is from dividends paid or distributions made by the Company's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by the Company's subsidiaries.

Both the Company and OTP's credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of December 31, 2012 the Company was in compliance with the debt covenants. See note 10 for further information on the covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between 46.3% and 56.7%. OTP's equity to total capitalization ratio was 52.0% as of December 31, 2012. Total capitalization for OTP cannot exceed $809 million.

9. Commitments and Contingencies

Construction and Other Purchase Commitments
At December 31, 2012 OTP had commitments under contracts in connection with construction programs aggregating approximately $79,413,000.

Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts
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 2014, 2016 and 2040. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they provide for recovery of most fuel costs. See table below for schedule of commitments.

Operating Leases
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 $11,858,000, $10,061,000 and $10,414,000 for 2012, 2011 and 2010, 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, 2012, are as follows:

(in thousands)	Capacity and Energy Requirements	Coal and Freight Purchase Commitments	Operating Leases OTP	Operating Leases Nonelectric	Operating Leases Total
2013	$ 30,964	$ 42,875	$2,464	$ 5,961	$ 8,425
2014	15,980	20,384	2,150	4,830	6,980
2015	13,762	16,886	1,602	4,261	5,863
2016	16,511	20,803	1,320	3,465	4,785
2017	15,868	22,047	978	2,355	3,333
Beyond 2017	77,040	673,961	12,787	549	13,336
Total	$ 170,125	$ 796,956	$21,301	$ 21,421	$ 42,722

Contingencies

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, environmental remediation, litigation matters and the resolution of matters related to open tax years. Should all of these items result in liabilities being incurred, the loss could be as high as $2.0 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, such as possible warranty claims on products that are beyond their warranty period but where a customer may claim to have provided notice of a defect while the product was under warranty. If these claims were to occur, it could result in the Company incurring a significantly greater liability than it anticipates.

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, 2012 will not be material.

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, 2012 and December 31, 2011:

(in thousands)	Line Limit	In Use on December 31, 2012	Restricted due to Outstanding Letters of Credit	Available on December 31, 2012	Available on December 31, 2011
Otter Tail Corporation Credit Agreement	$150,000	$ --	$ 733	$ 149,267	$ 198,776
OTP Credit Agreement	170,000	--	3,189	166,811	165,950
Total	$320,000	$ --	$ 3,922	$ 316,078	$ 364,726

Under the Otter Tail Corporation Credit Agreement referenced below, the maximum amount of debt outstanding in 2012 was $66,236,000 on July 13, 2012 and the average daily balance of debt outstanding during 2012 was $12,078,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2012 was 3.8% compared with 3.7% in 2011. Under the OTP Credit Agreement referenced below, the maximum amount of debt outstanding in 2012 was $16,582,000 on August 15, 2012 and the average daily balance of debt outstanding during 2012 was $5,867,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2012 was 1.7% compared with 1.5% in 2011.

On October 29, 2012 the Company entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement) with the Banks named therein, which is an unsecured $150 million revolving credit facility that the Company can draw on to support its operations and the operations of the businesses of Varistar. The Otter Tail Corporation Credit Agreement amends and restates the Company's Second Amended and Restated Credit Agreement dated as of May 4, 2010, which was set to expire on May 4, 2013, and provided for a $200 million line of credit. Borrowings under the Otter Tail Corporation Credit Agreement currently bear interest at LIBOR plus 1.75%, subject to adjustment based on the Company's senior unsecured credit ratings. The interest rate being charged under the Second Amended and Restated Credit Agreement prior to the renewal was LIBOR plus 3.25%. Under the Otter Tail Corporation Credit Agreement, the Company 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 Otter Tail Corporation Credit Agreement is set to expire on October 29, 2017. The Otter Tail Corporation Credit Agreement contains a number of restrictions on the Company and the businesses of Varistar, and its material subsidiaries, including restrictions on the Company's and Varistar's ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains certain financial covenants. Specifically, the Company must not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (each as defined in the Otter Tail Corporation Credit Agreement) to be greater than 0.60 to 1.00 as of the last day of any fiscal quarter of the Company, or permit its "Interest and Dividend Coverage Ratio" (as defined in the Otter Tail Corporation Credit Agreement) for any period of four consecutive fiscal quarters to be less than 1.50 to 1.00. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default. It 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 Otter Tail Corporation Credit Agreement are guaranteed by certain of the Company’s material subsidiaries. Outstanding letters of credit issued by the Company under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million. The Otter Tail Corporation Credit Agreement has an accordion feature whereby the line can be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement) with the Banks named therein. The OTP Credit Agreement amends and restates the $170 million OTP Credit Agreement dated as of March 3, 2011, which was set to expire on March 3, 2016. The OTP Credit Agreement 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 OTP Credit Agreement currently bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. The interest rate being charged under the OTP Credit Agreement prior to the renewal was LIBOR plus 1.5%. 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 is set to expire on October 29, 2017. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, as well as a financial covenant under which OTP may not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (as defined in the OTP Credit Agreement) to be greater than 0.60 to 1.00. The prior OTP Credit Agreement included similar covenants and events of default, but also included a financial covenant that is not included in the current OTP Credit Agreement, under which OTP could not permit its "Interest and Dividend Coverage Ratio" (as defined in the prior OTP Credit Agreement) to be less than 1.50 to 1.00. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

On May 11, 2012 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 July 13, 2012 the Company prepaid in full its outstanding $50 million, 8.89% Senior Unsecured Note due November 30, 2017 (the Cascade Note) issued pursuant to the Note Purchase Agreement dated as of February 23, 2007, as amended, between the Company and Cascade Investment, L.L.C. (Cascade). Immediately before the prepayment, the Cascade Note bore interest at 8.89% annually. The price paid by the Company to prepay the Cascade

Note was $63,031,000, which included the principal amount of the Cascade Note plus accrued interest of $531,000 and a negotiated prepayment premium of $12,500,000. The Company used funds available under the Otter Tail Corporation Credit Agreement for the prepayment. This early retirement reflects the Company's desire to lower its long-term debt outstanding given its recent divestitures. On repayment, $606,000 in unamortized debt expense related to this note was immediately recognized as expense along with the $12,500,000 negotiated prepayment premium, which, in total, reduced diluted earnings per share by $0.22 in the nine months ended September 30, 2012. Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2012.

In the third quarter of 2012, $25,000 of Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017, and $35,000 of Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022, were redeemed for estate settlement purposes.

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 (the 2007 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 and the 2011 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 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, and each contains a number of restrictions on OTP. These include restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2012 for each of the next five years are:

(in thousands)	2013	2014	2015	2016	2017
Aggregate amounts of Debt Maturities	$ 176	$ 188	$ 201	$ 100,206	$ 38,284

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, 2012 and December 31, 2011:

December 31, 2012 (in thousands)	OTP	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	5,065		5,065
Senior Unsecured Notes 4.63%, due December 1, 2021	140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,070		20,070
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000

Other Obligations - Various up to 3.95% at December 31, 2012		1,725	1,725
Total	$320,135	$ 101,725	$ 421,860
Less: Current Maturities	--	176	176
Unamortized Debt Discount	--	4	4
Total Long-Term Debt	$320,135	$ 101,545	$ 421,680
Total Short-Term and Long-Term Debt (with current maturities)	$320,135	$ 101,721	$ 421,856

December 31, 2011 (in thousands)	OTP	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		1,889	1,889
Total	$320,195	$ 151,889	$ 472,084
Less: Current Maturities	--	165	165
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	$ 151,885	$ 472,080

Financial Covenants

As of December 31, 2012 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 OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.

Under the 2007 Note Purchase Agreement, 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)	2012	2011	2010
Service Cost--Benefit Earned During the Period	$5,084	$4,415	$4,654
Interest Cost on Projected Benefit Obligation	12,465	12,666	12,067
Expected Return on Assets	(14,430)	(14,140)	(13,711)
Amortization of Prior-Service Cost	409	434	683
Amortization of Net Actuarial Loss	5,041	2,617	2,002
Net Periodic Pension Cost	$8,569	$5,992	$5,695

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

	2012	2011	2010
Discount Rate	5.15 %	6.00 %	6.00 %
Long-Term Rate of Return on Plan Assets	8.00 %	8.00 %	8.50 %
Rate of Increase in Future Compensation Level	3.38 %	3.75 %	3.75 %

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

(in thousands)	2012	2011
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 1,109	$ 1,507
Unrecognized Actuarial Loss	98,808	89,820
Total Regulatory Assets	99,917	91,327
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	22	28
Unrecognized Actuarial Loss	1,114	1,131
Total Accumulated Other Comprehensive Loss	1,136	1,159
Deferred Income Taxes	758	772
Noncurrent Liability	$ 84,616	$ 77,495

Funded status as of December 31:

(in thousands)	2012	2011
Accumulated Benefit Obligation	$ (238,706)	$ (211,324)
Projected Benefit Obligation	$ (275,634)	$ (246,098)
Fair Value of Plan Assets	191,018	168,603
Funded Status	$ (84,616)	$ (77,495)

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)	2012	2011
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$168,603	$171,308
Actual Return on Plan Assets	22,656	6,764
Discretionary Company Contributions	10,000	--
Benefit Payments	(10,241)	(9,469)
Fair Value of Plan Assets at December 31	$191,018	$168,603
Estimated Asset Return	13.44 %	4.06 %
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$246,098	$217,049
Service Cost	5,084	4,415
Interest Cost	12,465	12,666
Benefit Payments	(10,241)	(9,469)
Actuarial Loss	22,228	21,437
Projected Benefit Obligation at December 31	$275,634	$246,098

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

	2012	2011
Discount Rate	4.50 %	5.15 %
Rate of Increase in Future Compensation Level	3.13 %	3.38 %

The assumed rate of return on pension fund assets used for the determination of 2013 net periodic pension cost is 7.75%. 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:	2012	2011
Net Periodic Pension Cost	January 1, 2012	January 1, 2011

End of Year Benefit Obligations

	January 1, 2012 projected to December 31, 2012	January 1, 2011 projected to December 31, 2011
Market Value of Assets	December 31, 2012	December 31, 2011

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The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2013 are:

(in thousands)	2013
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 333
Amortization of Unrecognized Actuarial Loss	6,652
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	9
Amortization of Unrecognized Actuarial Loss	178
Total Estimated Amortization	$ 7,172

Cash flows—The Company had no minimum funding requirement as of December 31, 2012, but made a discretionary plan contribution of $10,000,000 in January 2013.

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

(in thousands)	2013	2014	2015	2016	2017	Years 2018-2022
	$ 10,747	$ 11,095	$ 11,591	$ 12,117	$ 12,844	$77,356

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 Investment Committee 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 Investment Committee 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 Company's Investment Committee. Each of the asset categories is within its respective tactical range. The Investment Committee 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	44 %	34%-54 %
Alternatives	5 %	0%-12 %
Cash	0 %	0%-5 %

The Company's pension plan asset allocations at December 31, 2012 and 2011, by asset category are as follows:

Asset Allocation	2012		2011	
Large Capitalization Equity Securities	24.7	%	25.7	%
International Equity Securities	17.8	%	14.4	%
Small and Mid-Capitalization Equity Securities	7.1	%	6.9	%
SEI Dynamic Asset Allocation Fund	4.8	%	4.8	%
Equity Securities	54.4	%	51.8	%
Fixed-Income Securities and Cash	41.1	%	43.4	%
Other - SEI Special Situation Collective Investment Trust	4.5	%	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, 2012 and 2011:

2012 (in thousands)		Level 1		Level 2		Level 3
Large Capitalization Equity Securities	$	47,083				
International Equity Securities		34,088				
Small and Mid-Capitalization Equity Securities		13,613				
SEI Dynamic Asset Allocation Fund		9,177				
Fixed Income Securities		78,480				
Cash Management – Money Market Fund		11				
SEI Special Situation Collective Investment Trust					$	8,566
Total Assets	$	182,452	$	--	$	8,566
2011 (in thousands)						
Large Capitalization Equity Securities	$	43,334				
International Equity Securities		24,294				
Small and Mid-Capitalization Equity Securities		11,567				
SEI Dynamic Asset Allocation Fund		8,133				

Fixed Income Securities		72,233				
Cash Management – Working Capital Account			$	911		
SEI Special Situation Collective Investment Trust					$	8,131
Total Assets	$	159,561	$	911	$	8,131

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, 2012. 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)	2012	2011	2010
Service Cost--Benefit Earned During the Period	$45	$81	$660
Interest Cost on Projected Benefit Obligation	1,479	1,632	1,670
Amortization of Prior Service Cost	73	73	74
Amortization of Net Actuarial Loss	327	245	477
Net Periodic Pension Cost	$1,924	$2,031	$2,881

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

	2012	2011	2010
Discount Rate	5.15 %	6.00 %	6.00 %
Rate of Increase in Future Compensation Level	4.59 %	4.65 %	4.69 %

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

(in thousands)	2012	2011
Regulatory Assets:		
Unrecognized Prior Service Cost	$135	$215
Unrecognized Actuarial Loss	2,788	2,427
Total Regulatory Assets	2,923	2,642
Projected Benefit Obligation Liability – Net Amount Recognized	(31,925)	(29,323)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	187	184
Unrecognized Actuarial Loss	3,057	2,067
Total Accumulated Other Comprehensive Loss	3,244	2,251
Deferred Income Taxes	2,163	1,500
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(23,595)	$(22,930)

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, 2012 and a statement of the funded status as of December 31 of both years:

(in thousands)	2012	2011
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Employer Contributions	1,259	1,072
Benefit Payments	(1,259)	(1,072)
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		

Projected Benefit Obligation at January 1	$29,323	$27,797
Service Cost	45	81
Interest Cost	1,479	1,632
Benefit Payments	(1,259)	(1,072)
Plan Amendments	--	--
Actuarial (Gain) Loss	2,337	885
Projected Benefit Obligation at December 31	$31,925	$29,323
Reconciliation of Funded Status:		
Funded Status at December 31	$(31,925)	$(29,323)
Unrecognized Net Actuarial Loss	7,882	5,872
Unrecognized Prior Service Cost	448	521
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(23,595)	$(22,930)

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

	2012	2011
Discount Rate	4.50 %	5.15 %
Rate of Increase in Future Compensation Level	3.19 %	4.59 %

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 2013 are:

(in thousands)	2013
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 22
Amortization of Unrecognized Actuarial Loss	208
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	51
Amortization of Unrecognized Actuarial Loss	313
Total Estimated Amortization	$ 594

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)	2013	2014	2015	2016	2017	Years 2018-2022
	$ 1,197	$ 1,239	$ 1,403	$ 1,391	$ 1,362	$ 7,954

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)	2012	2011	2010
Service Cost--Benefit Earned During the Period	$1,799	$1,524	$1,634
Interest Cost on Projected Benefit Obligation	3,500	3,418	3,207
Amortization of Transition Obligation	748	748	748
Amortization of Prior Service Cost	211	211	211
Amortization of Net Actuarial Loss	1,517	835	832
Expense Decrease Due to Medicare Part D Subsidy	(2,039)	(2,118)	(2,078)
Net Periodic Postretirement Benefit Cost	$5,736	$4,618	$4,554

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

	2012	2011	2010
Discount Rate	5.05 %	5.75 %	5.75 %

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

(in thousands)	2012	2011
Regulatory Asset:		
Unrecognized Transition Obligation	$--	$723
Unrecognized Prior Service Cost	745	950
Unrecognized Net Actuarial Loss	14,364	6,736
Net Regulatory Asset	15,109	8,409
Projected Benefit Obligation Liability – Net Amount Recognized	(58,883)	(48,263)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	--	15
Unrecognized Prior Service Cost	14	17
Unrecognized Net Actuarial Loss (Gain)	106	4
Accumulated Other Comprehensive Loss	120	36
Deferred Income Taxes	80	24
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$(43,574)	$(39,794)

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, 2012:

(in thousands)	2012	2011
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$--	$--
Actual Return on Plan Assets	--	--
Company Contributions	1,956	2,066
Benefit Payments (Net of Medicare Part D Subsidy)	(4,296)	(4,119)
Participant Premium Payments	2,340	2,053
Fair Value of Plan Assets at December 31	$--	$--
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$48,263	$42,372
Service Cost (Net of Medicare Part D Subsidy)	1,544	1,275
Interest Cost (Net of Medicare Part D Subsidy)	2,575	2,384
Benefit Payments (Net of Medicare Part D Subsidy)	(4,296)	(4,119)
Participant Premium Payments	2,340	2,053
Actuarial Loss	8,457	4,298
Projected Benefit Obligation at December 31	$58,883	$48,263
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$(39,794)	$(37,242)
Expense	(5,736)	(4,618)
Net Company Contribution	1,956	2,066
Accrued Postretirement Cost at December 31	$(43,574)	$(39,794)

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

	2012	2011
Discount Rate	4.25 %	5.05 %

Assumed healthcare cost-trend rates as of December 31:

	2012	2011

Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.62	%	6.78	%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.01	%	7.21	%
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 2012 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 7,725	$(6,401)
Effect on Total of Service and Interest Cost	$ 700	$(560)
Effect on Expense	$ 1,330	$(1,088)

Measurement Dates:	2012	2011
Net Periodic Postretirement Benefit Cost	January 1, 2012	January 1, 2011
End of Year Benefit Obligations	January 1, 2012 projected to December 31, 2012	January 1, 2011 projected to December 31, 2011

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 2013 are:

(in thousands)	2013
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 205
Amortization of Unrecognized Actuarial Loss	991
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Loss	26
Total Estimated Amortization	$ 1,227

Cash flows—The Company expects to contribute $2.9 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2013. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $502,000 in 2013. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2013	2014	2015	2016	2017	Years 2018-2022
	$ 2,903	$ 3,067	$ 3,170	$ 3,305	$ 3,517	$20,006

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 included in continuing operations totaled $2,553,000 for 2012, $2,598,000 for 2011 and $2,122,000 for 2010.

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 $735,000 for 2012, $760,000 for 2011 and $779,000 for 2010.

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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 market indications of rates available to the Company for the issuance of debt. The fair value measurements of the Company's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820, Fair Value Measurement.

	December 31, 2012		December 31, 2011	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 52,362	$ 52,362	$ 15,994	$ 15,994
Long-Term Debt	(421,680)	(491,244)	(471,915)	(525,041)

14. Property, Plant and Equipment

(in thousands)	December 31, 2012	December 31, 2011
Electric Plant in Service		
Production	$ 672,120	$ 669,805
Transmission	261,447	229,320
Distribution	405,461	390,383
General	84,275	83,026
Electric Plant in Service	1,423,303	1,372,534
Construction Work in Progress	75,758	49,123
Total Gross Electric Plant	1,499,061	1,421,657
Less Accumulated Depreciation and Amortization	526,467	499,327
Net Electric Plant	$ 972,594	$ 922,330
Nonelectric Operations Plant		
Equipment	$ 144,901	$ 137,644
Buildings and Leasehold Improvements	37,209	35,726
Land	3,984	3,958
Nonelectric Operations Plant	186,094	177,328
Construction Work in Progress	2,132	3,628
Total Gross Nonelectric Plant	188,226	180,956
Less Accumulated Depreciation and Amortization	111,368	100,424
Net Nonelectric Operations Plant	$ 76,858	$ 80,532
Net Plant	$ 1,049,452	$ 1,002,862

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 2012, 2011 and 2010) to net income before total income tax expense for the following reasons:

(in thousands)	2012	2011	2010
Tax Computed at Federal Statutory Rate	$14,385	$13,661	$10,329
Increases (Decreases) in Tax from:			
Federal Production Tax Credit	(6,695)	(7,281)	(6,441)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(891)	(996)	(1,163)
State Income Taxes Net of Federal Income Tax Benefit	(849)	798	(1,186)
Investment Tax Credit Amortization	(720)	(855)	(926)
Dividend Received/Paid Deduction	(656)	(677)	(692)
Corporate Owned Life Insurance	(585)	(388)	(556)
Impact of Medicare Part D Change	(584)	(599)	1,692
Allowance for Funds Used During Construction - Equity	(409)	(301)	(1)
Tax Depreciation - Treasury Grant for Wind Farms	(304)	(507)	(845)
Differences Reversing in Excess of Federal Rates	(143)	680	989
Permanent and Other Differences	(416)	586	2,031
Total Income Tax Expense – Continuing Operations	$2,133	$4,121	$3,231
Income Tax (Benefit) Expense – Discontinued Operations	(14,667)	(13,404)	720
Income Tax (Benefit) Expense – Continuing and Discontinued Operations	$(12,534)	$(9,283)	$3,951
Overall Effective Federal, State and Foreign Income Tax Rate	70.4%	41.2%	151.5%
Income Tax Expense From Continuing Operations Includes the Following:			
Current Federal Income Taxes	$(7,198)	$(4,303)	$(14,156)
Current State Income Taxes	(1,402)	(754)	3,448
Deferred Federal Income Taxes	15,878	14,308	25,166
Deferred State Income Taxes	3,161	4,002	(2,697)
Federal Production Tax Credit	(6,695)	(7,281)	(6,441)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(891)	(996)	(1,163)
Investment Tax Credit Amortization	(720)	(855)	(926)
Total	$2,133	$4,121	$3,231
(Loss) Income Before Income Taxes – U.S.	$(13,426)	$(7,547)	$13,670
Loss Before Income Taxes – Foreign	(4,381)	(14,979)	(11,063)
Total Income Before Income Taxes – Continuing and Discontinued Operations	$(17,807)	$(22,526)	$2,607

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

(in thousands)	2012	2011
Deferred Tax Assets		
North Dakota Wind Tax Credits	$44,172	$44,370
Benefit Liabilities	35,459	35,006
Retirement Benefits Liabilities	34,618	27,214
Net Operating Loss Carryforward	27,682	7,727
Federal Production Tax Credits	27,048	20,354

Cost of Removal	25,869	25,777
Differences Related to Property	12,983	10,227
Investment Tax Credits	2,554	3,379
Vacation Accrual	2,017	1,945
Other	10,853	9,393
Total Deferred Tax Assets	$223,255	$185,392
Deferred Tax Liabilities		
Differences Related to Property	$(301,991)	$(289,542)
Retirement Benefits Regulatory Asset	(34,618)	(27,214)
North Dakota Wind Tax Credits	(11,923)	(11,850)
Excess Tax over Book Pension	(6,995)	(6,353)
Impact of State Net Operating Losses on Federal Taxes	(3,484)	(2,710)
Regulatory Asset	(1,691)	(1,969)
Renewable Resource Rider Accrued Revenue	(934)	(1,913)
Other	(2,442)	(7,630)
Total Deferred Tax Liabilities	$(364,078)	$(349,181)
Deferred Income Taxes	$(140,823)	$(163,789)

Schedule of expiration of tax net operating losses and tax credits available as of December 31, 2012:

(in thousands)	Amount	2013	2014	2015	2016	2024-33
United States						
Federal Net Operating Losses	$ 17,824	$ --	$ --	$ --	$ --	$17,824
Federal Tax Credits	28,051	--	--	--	--	28,051
State Net Operating Losses	9,955	--	--	--	--	9,955
State Tax Credits	43,400	2,461	1,950	1,950	1,950	35,089

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)	2012	2011	2010
Balance on January 1	$ 12,138	$ 900	$ 900
Increases Related to Tax Positions for Prior Years	--	11,238	--
Decreases Related to Tax Positions for Prior Years	(6,802)		
Uncertain Positions Resolved During Year	(900)	--	--
Balance on December 31	$ 4,436	$ 12,138	$ 900

The balance of unrecognized tax benefits as of December 31, 2012 would not reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2012 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. There was no amount accrued for interest on tax uncertainties as of December 31, 2012.

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, 2012, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2009.

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 2012.

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, 2012 and 2011 are presented in the following table:

(in thousands)	2012	2011
Asset Retirement Obligations		
Beginning Balance	$ 4,808	$ 4,402
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	(20)	22
Accrued Accretion	419	384
Settlements	--	--
Ending Balance	$ 5,207	$ 4,808
Asset Retirement Costs Capitalized		
Beginning Balance	$ 1,497	$ 1,497
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	(20)	--
Settlements	--	--
Ending Balance	$ 1,477	$ 1,497
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$ 351	$ 290
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	4
Depreciation Expense	56	57
Settlements	--	--
Ending Balance	$ 407	$ 351
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 February 8, 2013 the Company sold substantially all of the assets of ShoreMaster, its waterfront equipment manufacturer, for approximately $13.0 million in cash, subject to certain closing conditions. The Company recorded a $4.6 million net-of-tax impairment of ShoreMaster's assets in December 2012 based on the market value of the assets. On November 30, 2012 the Company completed the sale of the fixed assets of DMI, its wind tower manufacturing company, for total proceeds, net of commissions and selling costs, of $18.1 million. On February 29, 2012 the Company completed the sale of DMS, its health services company, for $24.0 million in cash net of commissions and selling costs. On January 18, 2012, the Company sold the assets of Aviva for $0.3 million in cash. For discontinued operations reporting, Aviva's results are included in ShoreMaster's consolidated results. On December 29, 2011 the Company completed the sale of Wylie for approximately $25.0 million in cash. On May 6, 2011 the Company completed the sale of IPH for approximately $86.0 million in cash. For segment reporting, prior to being included in discontinued operations, ShoreMaster was included in the Company's Manufacturing segment, DMI and Wylie made up the Company's former Wind Energy segment, DMS was the only business in the Company's former Health Services segment and IPH was the only business in the Company's former Food Ingredient Processing segment. The Company's Wind Energy, Health Services and Food Ingredient Processing segments were eliminated as a result of the sales of DMI, Wylie, DMS and IPH.

As of December 31, 2012 the Company met the ASC 360-10-45 criteria for assets held for sale for the ShoreMaster transaction and appropriately classified the assets as held for sale on December 31, 2012 and, as such, ShoreMaster's activities were required to be reported in discontinued operations in accordance with ASC 205-20-45.

Following are summary presentations of the results of discontinued operations for the years ended December 31, 2012, 2011 and 2010, along with the major components of assets and liabilities of discontinued operations as of December 31, 2012 and 2011:

	For the Year Ended December 31, 2012						
(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Intercompany transactions adjustment	Total
Operating Revenues	$ 186,151	$ --	$ 32,563	$ 16,362	$ --	$ (2,017)	$ 233,059
Operating Expenses	184,462	179	36,163	14,741	--	(2,017)	233,528
Asset Impairment Charge	45,573	--	7,747	--	--	--	53,320
Operating (Loss) Income	(43,884)	(179)	(11,347)	1,621	--	--	(53,789)
Other Income	135	--	15	122	--	--	272
Interest Expense	5,787	--	1,553	279	--	(7,444)	175
Income Tax (Benefit) Expense	(15,792)	13	(4,021)	1,734	106	2,978	(14,982)
Net Loss from Operations	(33,744)	(192)	(8,864)	(270)	(106)	4,466	(38,710)
Loss on Disposition Before Taxes	--	(62)	--	(5,154)	--	--	(5,216)
Income Tax Expense (Benefit) on Disposition	--	460	--	(145)	--	--	315
Net Loss on Disposition	--	(522)	--	(5,009)	--	--	(5,531)

Net Loss	$ (33,744)	$ (714)	$ (8,864)	$ (5,279)	$ (106)	$ 4,466	$ (44,241)

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For the Year Ended December 31, 2011

(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Intercompany transactions adjustment	Total
Operating Revenues	$ 201,921	$ 49,884	$ 39,863	$ 89,558	$ 28,125	$ (6,016)	$ 403,335
Operating Expenses	218,542	55,927	41,478	85,244	24,046	(6,016)	419,221
Asset Impairment Charge	3,142	--	456	56,379	--	--	59,977
Operating (Loss) Income	(19,763)	(6,043)	(2,071)	(52,065)	4,079	--	(75,863)
Other (Deductions) Income	(46)	18	1	281	(228)	(3)	23
Interest Expense	6,852	709	1,580	1,726	11	(10,636)	242
Income Tax (Benefit) Expense	(4,768)	(2,683)	(1,462)	(16,058)	1,462	4,254	(19,255)
Net (Loss) Income from Operations	(21,893)	(4,051)	(2,188)	(37,452)	2,378	6,379	(56,827)
(Loss) Gain on Disposition Before Taxes	--	(946)	--	--	15,471	--	14,525
Income Tax Expense on Disposition	--	2,854	--	--	2,997	--	5,851
Net (Loss) Gain on Disposition	--	(3,800)	--	--	12,474	--	8,674
Net (Loss) Income	$ (21,893)	$ (7,851)	$ (2,188)	$ (37,452)	$ 14,852	$ 6,379	$ (48,153)

For the Year Ended December 31, 2010

(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Intercompany transactions adjustment	Total
Operating Revenues	$ 143,603	$ 54,143	$ 35,624	$ 100,301	$ 77,412	$ (5,830)	$ 405,253
Operating Expenses	159,646	52,311	41,351	98,794	65,261	(5,830)	411,533
Asset Impairment Charge	--	--	19,740	--	--	--	19,740
Operating Income (Loss)	(16,043)	1,832	(25,467)	1,507	12,151	--	(26,020)
Other (Deductions) Income	(734)	8	21	331	(326)	--	(700)
Interest Expense	5,614	522	1,492	1,289	111	(8,844)	184
Income Tax (Benefit) Expense	(356)	511	(7,058)	369	3,716	3,538	720
Net (Loss) Income	$ (22,035)	$ 807	$ (19,880)	$ 180	$ 7,998	$ 5,306	$ (27,624)

December 31, 2012

(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Total
Current Assets	$ 1,367	$ --	$ 17,120	$ --	$ --	$ 18,487

Investments	--	--	85	--	--	85
Net Plant	--	--	520	--	--	520
Assets of Discontinued Operations	$ 1,367	$ --	$ 17,725	$ --	$ --	$ 19,092
Current Liabilities	$ 4,587	$ --	$ 6,569	$ --	$ --	$ 11,156
Liabilities of Discontinued Operations	$ 4,587	$ --	$ 6,569	$ --	$ --	$ 11,156

	December 31, 2011					
(in thousands)	DMI	Wylie	ShoreMaster	DMS	IPH	Total
Current Assets	$80,897	$--	$ 24,311	$29,375	$--	$134,583
Goodwill	287	--	--	--	--	287
Net Plant	68,050	--	6,637	372	--	75,059
Assets of Discontinued Operations	$149,234	$--	$ 30,948	$29,747	$--	$209,929
Current Liabilities	$24,012	$--	$ 8,462	$14,341	$--	$46,815
Other Noncurrent Liabilities	900	--	--	--	--	900
Deferred Income Taxes	4,512	--	(791)	(1,579)	--	2,142
Deferred Credits - Other	--	--	--	119	--	119
Long-Term Debt	--	--	--	715	--	715
Liabilities of Discontinued Operations	$29,424	$--	$ 7,671	$13,596	$--	$50,691

Supplementary Financial Information

Quarterly Information (not audited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings (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 DMI and ShoreMaster, which were classified as discontinued operations in the fourth quarter of 2012. 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)	2012[2]	2011	2012[3]	2011	2012	2011	2012[4]	2011[5]
Operating Revenues[1]	$219,890	$194,281	$211,401	$216,677	$215,316	$221,946	$212,632	$207,265
Operating Income (Loss)[1]	18,255	20,626	15,246	19,068	24,373	19,562	24,153	12,641
Net Income (Loss):								
Continuing Operations	$10,175	$10,019	$6,901	$9,808	$4,801	$9,091	$17,091	$5,992
Discontinued Operations	(2,932)	(4,323)	(24,257)	9,020	(2,928)	(2,723)	(14,124)	(50,127)
	$7,243	$5,696	$(17,356))	$18,828	$1,873	$6,368	$2,967	$(44,135)
Earnings (Loss) Available for Common Shares:								
Continuing Operations	$9,991	$9,835	$6,717	$9,624	$4,618	$8,907	$16,906	$5,808
Discontinued Operations	(2,932)	(4,323)	(24,257)	8,698	(2,928)	(2,723)	(14,124)	(50,127)
	$7,059	$5,512	$(17,540)	$18,322	$1,690	$6,184	$2,782	$(44,319)
Basic Earnings (Loss) Per Share:								
Continuing Operations	$.28	$.27	$.19	$.27	$.13	$.25	$.47	$.16
Discontinued Operations	(.08)	(.12)	(.68)	.24	(.08)	(.08)	(.39)	(1.39)
	$.20	$.15	$(.49)	$.51	$.05	$.17	$.08	$(1.23)
Diluted Earnings (Loss) Per Share								
Continuing Operations	$.28	$.27	$.19	$.27	$.13	$.25	$.47	$.16
Discontinued Operations	(.08)	(.12)	(.67)	.24	(.08)	(.08)	(.39)	(1.39)
	$.20	$.15	$(.48)	$.51	$.05	$.17	$.08	$(1.23)
Dividends Declared Per Common Share	$.2975	$.2975	$.2975	$.2975	$.2975	$.2975	$.2975	$.2975
Price Range:								
High	22.57	23.43	23.00	23.48	24.35	22.07	25.25	22.28

Low	20.70	21.01	20.86	20.54	22.50	18.28	22.86	17.53
Average Number of Common Shares Outstanding--Basic	35,995	35,877	36,031	35,926	36,061	35,933	36,062	35,953
Average Number of Common Shares Outstanding--Diluted	36,129	36,081	36,223	36,164	36,253	36,172	36,256	36,113

1 From continuing operations.

2 Results include pre-tax asset impairment charge of $0.4 million at OTESCO in continuing operations

3 Results include pre-tax asset impairment charge of $45.6 million at DMI in discontinued operations.

4 Results include pre-tax asset impairment charges of $7.7 million at ShoreMaster in discontinued operations.

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

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, 2012, 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, 2012.

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, 2012 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, 2012. 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, 2012, 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 63.

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 2013 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 2013 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 2013 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 2013 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 2013 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 2013 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" in the Company's definitive Proxy Statement for the 2013 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2012 about the Company's common stock that may be issued under all of its equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)	
Equity compensation plans approved by security holders:					
1999 Stock Incentive Plan	391,785	(1)	$ 6.28	957,359	(2)
1999 Employee Stock Purchase Plan	--		N/A	522,227	(3)
Equity compensation plans not approved by security holders	--		--	--	
Total	391,785		$ 6.28	1,479,586	

(1) Includes 161,600 and 38,400 performance based share awards made in 2012 and 2011, respectively, 60,665 restricted stock units outstanding as of December 31, 2012, and 38,623 phantom shares as part of the deferred director compensation program, 92,497 outstanding options as of December 31, 2012 and excludes 104,545 shares of restricted stock issued under the 1999 Stock Incentive Plan.

(2) The 1999 Stock Incentive Plan provides for the issuance of any shares available under the plan in the form of restricted stock, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights.

(3) Shares are issued based on employee's election to participate in the plan.

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

The information required by this Item is incorporated by reference to the information under "Policy and Procedures Regarding Transactions with Related Persons," "Election of Directors" and "Meetings and Committees of the Board of Directors" in the Company's definitive Proxy Statement for the 2013 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 2013 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

SCHEDULE 1 - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Balance Sheets, December 31

(in thousands)		2012		2011
ASSETS				
Current Assets				
Cash and Cash Equivalents	$	44,802	$	7,062
Accounts Receivable from Subsidiaries		3,587		5,795
Interest Receivable from Subsidiaries		317		361
Notes Receivable from Subsidiaries		17,157		145,205
Other		16,384		9,580
Total Current Assets		82,247		168,003
Investments in Subsidiaries		716,453		613,380
Notes Receivable from Subsidiaries		67,925		128,818
Deferred Income Taxes		18,042		16,515
Other Assets		24,584		26,371
Total Assets	$	909,251	$	953,087
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts Payable to Subsidiaries	$	5,035	$	3,725

Notes Payable to Subsidiaries	231,611	181,100
Other	6,223	5,432
Total Current Liabilities	242,869	190,257
Other Noncurrent Liabilities	27,363	24,162
Commitments and Contingencies		
Capitalization		
Long-Term Debt, Net of Current Maturities	101,545	151,720
Cumulative Preferred Shares	15,500	15,500
Common Shareholder Equity	521,974	571,448
Total Capitalization	639,019	738,668
Total Liabilities and Equity	$ 909,251	$ 953,087

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Statements of Income--For the Years Ended December 31

(in thousands)	2012	2011	2010
Operating Income (Loss)			
Revenue	$--	$--	$--
Operating Expenses	15,197	15,798	17,409
Operating Loss	(15,197)	(15,798)	(17,409)
Other Income (Expense)			
Equity Income (Loss) in Earnings of Subsidiaries	8,430	(4,205)	8,998
Loss on Early Retirement of Debt	(13,106)	--	--
Interest Charges	(13,994)	(17,157)	(17,084)
Interest Charges to Subsidiaries	(512)	(290)	(16)
Interest Income from Subsidiaries	15,700	18,006	15,887
Other Income	1,426	548	682
Total Other Income (Expense)	(2,056)	(3,098)	8,467
Income Before Income Taxes – Continuing Operations	(17,253)	(18,896)	(8,942)
Income Tax Benefit	(11,980)	(5,653)	(7,598)
Net Loss from Continuing Operations	(5,273)	(13,243)	(1,344)
Net Loss from Discontinued Operations	--	--	--
Total Net Loss	(5,273)	(13,243)	(1,344)
Preferred Dividend Requirement and Other Adjustments	736	1,058	833
Loss Available for Common Shares	$(6,009)	$(14,301)	$(2,177)

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Statements of Cash Flows--For the Years Ended December 31

(in thousands)	2012	2011	2010
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	$43,904	$30,833	$34,220
Cash Flows from Investing Activities			
Investment in Subsidiaries	(137,726)	(24,534)	(5,000)
Debt Repaid by (Issued to) Subsidiaries	239,452	98,521	(38,890)
Cash Used in Investing Activities	(69)	(99)	(686)
Net Cash Provided by (Used in) Investing Activities	101,657	73,888	(44,576)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	-	(253)	253
Net Short-Term (Repayments) Borrowings	-	(54,176)	48,176
Proceeds from Issuance of Common Stock	-	-	549
Common Stock Issuance Expenses	(370)	-	(141)
Payments for Retirement of Common Stock	(111)	(1,182)	(401)
Proceeds from Issuance of Long-Term Debt	-	2,006	-
Short-Term and Long-Term Debt Issuance Expenses	(700)	(14)	(1,674)
Payments for Retirement of Long-Term Debt	(50,164)	(117)	-
Premium Paid for Early Retirement of Long-Term Debt	(12,500)	-	-

Dividends Paid and Other Distributions	(43,976)	(43,923)	(43,698)
Net Cash Used in Financing Activities	(107,821)	(97,659)	3,064
Net Change in Cash and Cash Equivalents	37,740	7,062	(7,292)
Cash and Cash Equivalents at Beginning of Period	7,062	-	7,292
Cash and Cash Equivalents at End of Period	$44,802	$7,062	$-

See accompanying notes to condensed financial statements.

Otter Tail Corporation (Parent Company)
Notes to Condensed Financial Statements
For the years ended December 31, 2012, 2011 and 2010

Incorporated by reference are Otter Tail Corporation's consolidated statements of comprehensive income and common shareholders' equity in Part II, Item 8.

Basis of Presentation

The condensed financial information of Otter Tail Corporation is presented to comply with Rule 12-04 of Regulation S-X. The unconsolidated condensed financial statements do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read with the consolidated financial statements and related notes included in this Annual Report on Form 10-K.

Otter Tail Corporation's investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income (loss) from operations of the subsidiaries is reported on a net basis as equity income (loss) in earnings of subsidiaries.

Related Party Transactions

As of December 31, 2012:

(in thousands)	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long- Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$1,201	$--	$--	$ 15,500	$160	$--
Vinyltech Corporation	2	32	--	8,500	--	8,251
Northern Pipe Products, Inc.	--	9	--	3,725	--	10,537
BTD Manufacturing, Inc.	41	107	--	28,500	--	1,773
DMI Industries, Inc.	20	113	1,461	--	--	--
ShoreMaster, Inc.	40	12	15,696	--	--	--
T.O. Plastic, Inc.	--	28	--	7,400	--	2,986
Aevenia, Inc	50	7	--	1,800	--	1,480
Foley Company	40	9	--	2,500	--	1,189
Varistar Corporation	2,050	--	--	--	4,875	205,329
Otter Tail Energy Services Company	--	--	--	--	--	66
Otter Tail Assurance Limited	143	--	--	--	--	--
	$3,587	$317	$17,157	$ 67,925	$5,035	$231,611

As of December 31, 2011

(in thousands)	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$924	$--	$--	$15,500	$236	$--
Vinyltech Corporation	2	39	--	10,500	--	3,596
Northern Pipe Products, Inc.	2	17	--	5,889	--	5,085
BTD Manufacturing, Inc.	24	107	7,023	28,500	--	--

DMI Industries, Inc.	129	113	89,449	30,956	--	--
ShoreMaster, Inc.	68	12	30,382	3,654	--	--
DMS Health Group	20	29	3,329	22,118		--
T.O. Plastic, Inc.	--	28	1,978	7,400	--	--
Aevenia, Inc	--	7	2,319	1,800	--	--
Foley Company	12	9	9,452	2,500	--	--
Varistar Corporation	3,893	--	--	--	3,489	172,419
Otter Tail Energy Services Company	--	--	1,273	--	--	--
Otter Tail Assurance Limited	721	--	--	--	--	--
	$5,795	$361	$145,205	$128,817	$3,725	$181,100

Dividends

Dividends paid to Otter Tail Corporation (the Parent) from its subsidiaries were as follows (in thousands):

	2012	2011	2010
Cash Dividends Paid to Parent by Subsidiaries	$43,018	$43,320	$43,131

See Otter Tail Corporation's notes to consolidated financial statements in Part II, Item 8 for other disclosures.

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

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 8/23/07	4.1	—Note Purchase Agreement, dated as of August 20, 2007.
4-A-1	8-K filed 12/20/07	4.3	—First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007.
4-A-2	8-K filed 9/15/08	4.1	—Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007.
4-A-3	8-K filed 7/1/09	4.2	—Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007.
4-B	8-K filed 11/2/12	4.1	—Third Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Corporation, the Banks named therein, Bank of America, N.A. and JPMorgan Chase Bank, N.A., as Co-Syndication Agents, KeyBank National Association, as Documentation Agent, U.S. Bank National Association, as administration agent for the Banks and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners
4-C	8-K filed 11/2/12	4.2	—Second Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Power Company, the Banks named therein, JPMorgan Chase Bank, N.A. and Bank of America, N.A., as Co-Syndication Agents, KeyBank National Association and CoBank, ACB, as Co-Documentation Agents, U.S. Bank National Association, as administrative agent for the Banks, and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners.
4-D	8-K filed 8/3/11	4.1	—Note Purchase Agreement, dated as of July 29, 2011, between Otter Tail Power Company and the Purchasers named therein.

4-E	8-K filed 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-F-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.

	File No.	Previously Filed As Exhibit No.	
4-F-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.
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-F-3	

	10-K for year ended 12/31/91		—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).

	File No.	Previously Filed As Exhibit No.	
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.
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			—Lignite Sale Agreement between Coyote Creek Coal Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., Northwestern Corporation, dated as of October 10, 2012.**

10-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).

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	File No.	Previously Filed As Exhibit No.	
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-1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended.*
10-M-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-M-2	8-K filed 02/04/05	10.1	—Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-M-2a	10-K for year ended 12/31/06	10-N-2a	—First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-M-2b	10-K for year ended 12/31/10	10-N-2B	—Second Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-M-3	10-K for year ended 12/31/93	10-N-5	—Nonqualified Profit Sharing Plan.*
10-M-4	10-Q for quarter ended 3/31/02	10-B	—Nonqualified Retirement Savings Plan, as amended.*
10-M-5	10-Q for quarter ended 9/30/11	10.1	—Nonqualified Retirement Plan (2011 Restatement).*
10-M-6	10-Q for quarter ended 6/30/12	10.6	—Otter Tail Corporation Executive Restoration Plus Plan.
10-M-7	8-K filed 4/19/12	10.1	—1999 Employee Stock Purchase Plan, As Amended (2012).
10-M-8	8-K filed 4/13/06	10.4	—1999 Stock Incentive Plan, As Amended (2006).
10-M-9	10-K for year ended 12/31/05	10-N-7	—Form of Stock Option Agreement.*
10-M-10	8-K filed 4/19/12	10.2	—Form of 2012 Restricted Stock Award Agreement for Executive Officers.*
10-M-11	8-K filed 4/19/12	10.3	—Form of 2012 Performance Award Agreement.*
10-M-12	10-K for year ended 12/31/11	10-N-11	—Executive Annual Incentive Plan.*
10-M-13	8-K filed 4/19/12	10.4	—Form of 2012 Restricted Stock Unit Award Agreement.*
10-M-14	8-K filed 4/13/06	10.1	—Form of Restricted Stock Award Agreement for Directors.
10-N	8-K filed 5/14/12	1.1	—Distribution Agreement dated May 14, 2012, between Otter Tail Corporation and J.P. Morgan Securities LLC.