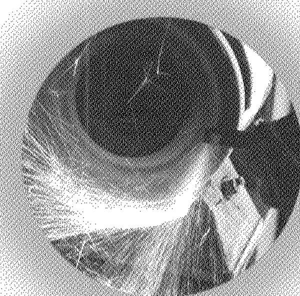
OTTER TAIL CORPORATION 2010 ANNUAL REPORT



SHARPENING OUR FOCUS
STRENGTHENING OUR POSITION

2010 ANNUAL REPORT

OTTER TAIL CORPORATION

OUR MISSION

To create the opportunity for strong companies and talented people to reach their full potential by providing an ideal combination of resources and an environment that rewards agility, accountability, and entrepreneurial spirit

SUMMARY OF THE YEAR

	2010	2009	Percent Change
CONSOLIDATED OPERATIONS:			
Total Operating Revenues	$ 1,119,084,000	$ 1,039,512,000	7.7
Net Income (Loss)	(1,344,000)	26,031,000	(105.2)
Basic Earnings (Loss) Per Share	(0.06)	0.71	(108.5)
Diluted Earnings (Loss) Per Share	(0.06)	0.71	(108.5)
Dividends Per Common Share	1.19	1.19	—
Return on Average Common Equity	(0.3)%	3.8%	(107.9)
Book Value Per Common Share	17.55	18.75	(6.4)
Cash Flow from Continuing Operations	105,017,000	162,750,000	(35.5)
Number of Common Shares Outstanding	36,002,739	35,812,280	0.5
Number of Common Shareholders	14,848	14,923	(0.5)
Closing Stock Price	22.54	24.82	(9.2)
Total Return (share price appreciation plus dividends)	(4.4)%	11.5%	(138.3)
Total Market Value of Common Stock	811,502,000	888,861,000	(8.7)
Total Full-time Employees (all companies and corporate)	3,901	3,562	9.5
ELECTRIC OPERATIONS:			
Operating Revenues:			
Retail	$ 301,080,000	$ 282,116,000	6.7
Wholesale—Net of Purchased Power Costs	23,197,000	15,762,000	47.2
Other	15,801,000	16,589,000	(4.8)
Total Electric Operating Revenues	$ 340,078,000	$ 314,467,000	8.1
Total Retail Electric Sales (kwh)	4,262,748,000	4,244,377,000	0.4
Operating Income	60,644,000	50,081,000	21.1
Electric Utility Customers	129,256	129,307	—
Gross Plant Investment	1,360,762,000	1,324,119,000	2.8
Total Assets	1,106,261,000	1,121,241,000	(1.3)
Capital Expenditures	43,121,000	146,128,000	(70.5)
Full-time Employees	681	698	(2.4)
NONELECTRIC OPERATIONS: (excluding corporate)			
Operating Revenues	$ 779,006,000	$ 725,045,000	7.4
Operating Income (Loss)	(9,866,000)	8,952,000	(210.2)
Total Assets	621,192,000	581,529,000	6.8
Capital Expenditures	41,645,000	30,433,000	36.8
Full-time Employees	3,162	2,805	12.7

TO OUR **SHAREHOLDERS**

JOHN ERICKSON
President and CEO

DEAR SHAREHOLDER > The demands of unpredictable economic cycles can challenge a company. But they also create a market environment that provides important opportunities—opportunities to take stock, to sharpen focus. In early 2010, as the U.S. economy began to slowly emerge from recession, we had the opportunity to gauge whether the actions taken over the last year had suitably equipped Otter Tail Corporation to benefit from this gradual—and sometimes mixed—period of recovery.

I'm pleased to say that those efforts largely held true in 2010. With the support of employees at each of our operating companies, Otter Tail Corporation is a leaner, more efficient entity than it was two years ago. Our collective efforts to improve our efficiency and maintain liquidity through difficult economic times had a favorable impact on our financial position. This deep commitment to financial strength continues.

We witnessed some positive trends in several of our operating companies during 2010. BTD Manufacturing, our metal fabrication business; T.O. Plastics, our custom plastic parts and packaging company; and Foley Company, our mechanical and general construction services business, experienced welcomed revenue upturns during the year.

Of course, challenges still exist, particularly with DMI Industries, our wind tower manufacturer, which I'll discuss later, and ShoreMaster, our waterfront products business.

ShoreMaster remains hard hit by the recession. That reality has impacted ongoing demand for ShoreMaster products, a significant percentage of which are supported by discretionary consumer spending, and required us to record an asset impairment charge for this business to more appropriately reflect its current value. ShoreMaster has made great strides in bringing its costs in line with current revenue levels and enters 2011 in a more favorable position.

While overall 2010 earnings were disappointing, our confidence in the long-term potential for Otter Tail Corporation is not diminished, and we are committed to capitalizing on the opportunities we see. In spite of prevailing challenges, our operating companies combined to deliver a consolidated revenue increase of 7.7% compared with 2009, and the majority of our operating segments generated higher net income. We begin 2011 substantially improved versus a year ago.

GROWTH FROM OUR FOUNDATION

A large part of the stability of Otter Tail Corporation comes from our electric business, Otter Tail Power Company. This business platform provides a solid foundation and gives us flexibility to optimize our portfolio of businesses as we move ahead. Historically, Otter Tail Power Company has been a stable and relatively predictable business with consistently solid performance.

Our electric business is also an important part of our growth strategy, and I envision it playing a larger role in the years ahead. Within the last four years, we have invested in initiatives, most notably wind, so that our renewable resources now account for about 14% of retail sales. We have significant additional transmission investment opportunities to pursue in the near term. We are confident in the long-term return potential of these actions and believe they benefit all of our stakeholders, including investors, customers, and the communities we serve.

WIND ENERGY CHALLENGE

Our opportunity in wind energy is unique and, given the 2010 financial performance of our wind tower manufacturer, DMI Industries, it merits a separate discussion. While we see meaningful opportunity in the market for wind energy, it's important to remember that the wind-power generation market is still an emerging and evolving one.

The wind industry continues to face near-term challenges, such as lengthened timetables for wind-farm development projects. Our focus for DMI is to build a clear leadership position by devoting ourselves to serving first-tier customers—the industry's top wind-turbine manufacturers—while remaining flexible enough to react to changing market conditions. That commitment provides opportunity as well as some hurdles.

DMI's performance last year reflects the adaptation that's sometimes needed to accommodate the requirements of world-class customers. During the past year, we incurred additional costs related to fulfilling the fabrication specifications for a key customer's new wind tower design. These efforts resulted in lower productivity and higher costs as they involved a combination of adding staff and reallocating existing resources within DMI to complete projects and support the customer's delivery requirements.

As we continue to work through issues like these, additional actions are being taken to improve production efficiency and to further the critical relationships that DMI continues to build with key wind turbine manufacturers.

2010 FINANCIAL RESULTS

Our financial results in 2010 reflect the impact of gradual overall economic improvement on certain of our operating companies and our ongoing focus on efficiency and cash flow generation. Results for the year also reflect the near-term challenges affecting DMI and noncash charges primarily related to ShoreMaster.

- Operating revenues increased 7.7% to $1.1 billion from $1.0 billion in 2009.
- Net loss was $1.3 million.
- Diluted earnings per share were ($.06) compared with $0.71 in 2009.
- 2010 results were impacted by a noncash asset impairment charge of $15.6 million, net-of-tax, and noncash charges to tax expense of $8.3 million.
- The common dividend paid in 2010 was $1.19 per share, providing a dividend yield of 4.8%.
- Our stock price decreased 9.2% in 2010, producing a total return to shareholders of (4.4%) in combination with the dividend.
- Operating cash flow totaled $105.0 million compared with $162.7 million in 2009.

We maintain a strong capital structure and have ample liquidity in our credit facilities to support our working capital requirements and help fuel growth initiatives.

STRENGTHENING OUR POSITION

We are committed to our vision of being among the country's leading diversified organizations with a strong electric business as our foundation. That vision encompasses our diversification strategy--a strategy that remains essential to our future, provides mechanisms for growth, and reduces risk in our portfolio of businesses. We are dedicated to pursuing a full range of opportunities to achieve this goal.

Also, we are committed to refining our portfolio to focus on the mix of businesses that we believe will reduce our risk profile and support our long-term strategy.

We have also taken steps to realign our businesses in a way that better reflects our current approach to achieving this vision. The realigned business platforms are as follows:

- Electric
- Wind Energy
- Manufacturing and Infrastructure
- Food Ingredient Processing
- Health Services

None of our success as an organization is possible without the commitment of a talented and devoted workforce. I have gained an even stronger appreciation for the efforts of all our employees over the last two years as they have worked to help ensure both the viability and, ultimately, the vitality of each of our operating companies as we move ahead.

It is my hope that during 2011 we will witness and benefit from a steadily improving economic environment. I pair that hope with the confidence that, by sharpening our focus and strengthening our position in the market, we are poised for long-term success.

On behalf of our management team and board of directors, I thank you for your continued support.

Sincerely,

John Erickson > President and CEO

OUR VISION

We will be among the country's leading diversified organizations, with a strong electric business as our foundation.

TO OUR EMPLOYEES

Otter Tail will mean exceptional talent thriving in an environment of opportunity and accountability that sets us apart from others.

TO OUR CUSTOMERS

Otter Tail will mean above-and-beyond commitment in everything we do, resulting in exceptional customer loyalty.

TO OUR SHAREHOLDERS

Otter Tail will mean executing on a solid diversification strategy to deliver an ROI that is consistently above average.

OUR VALUES

INTEGRITY

We conduct business responsibly and honestly.

SAFETY

We provide safe workplaces and require safe work practices.

PEOPLE

We build respectful relationships and create an environment where talented people thrive.

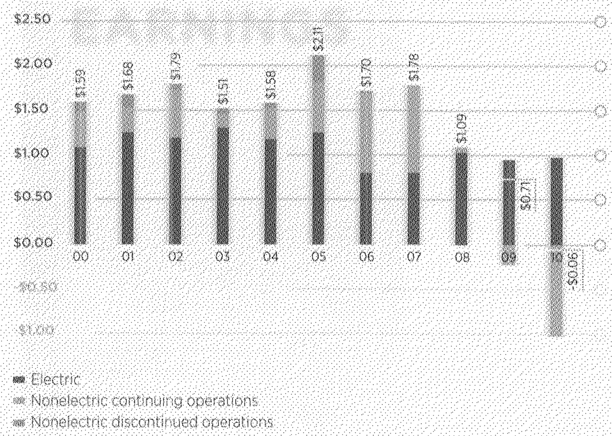
PERFORMANCE

We strive for excellence, act on opportunity and deliver on commitments.

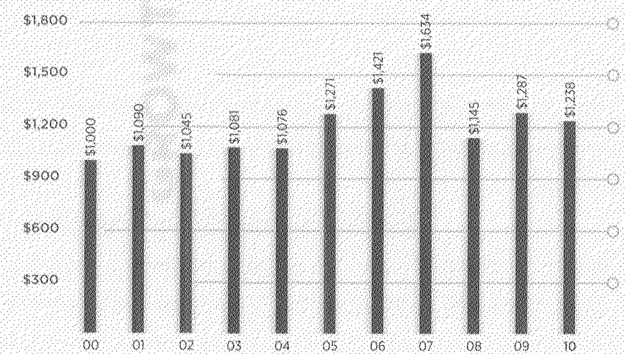
COMMUNITY

We improve the communities where we work and live.

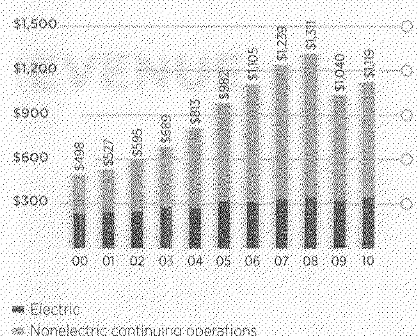
EARNINGS PER SHARE



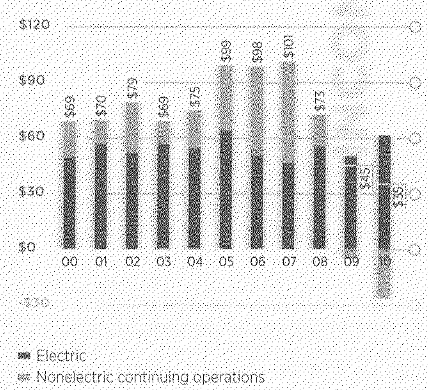
GROWTH OF $1,000 INVESTMENT IN OTTER TAIL COMMON STOCK MADE DECEMBER 31, 2000



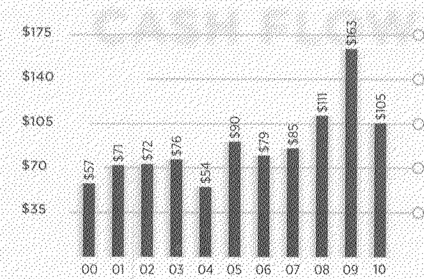
REVENUE GROWTH (millions)



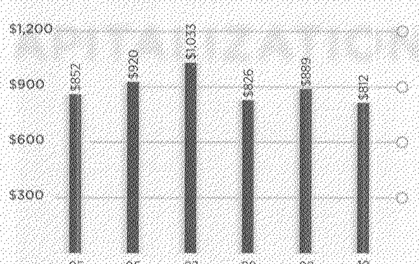
OPERATING INCOME (millions)



OPERATING CASH FLOWS (millions)

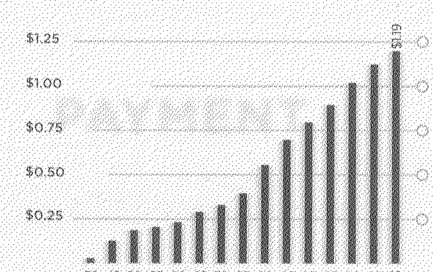


MARKET CAPITALIZATION (millions)



DIVIDEND PAYOUT RAIO

DIVIDEND PAYMENT HISTORY



SELECTED COMMON SHARE DATA	2010	2009	2008	2007	2006	2005
Market Price:						
High	$ 25.39	$ 25.40	$ 46.15	$ 39.39	$ 31.92	$ 31.95
Low	$ 18.24	$ 15.47	$ 14.99	$ 28.96	$ 25.78	$ 24.02
Common Price/Earnings Ratio:						
High	—	35.8	42.3	22.1	18.8	15.1
Low	—	21.8	13.8	16.3	15.2	11.4
Book Value Per Common Share	$ 17.55	$ 18.75	$ 19.10	$ 17.51	$ 16.62	$ 15.80

SELECTED DATA AND RATIOS	2010	2009	2008	2007	2006	2005
Interest Coverage Before Taxes (1)	1.7x	1.9x	2.8x	4.7x	5.2x	5.7x
Effective Income Tax Rate (2)	152%	(21)%	30%	34%	35%	34%
Return on Capitalization Including Short-Term Debt	3.1%	4.7%	5.5%	7.9%	8.8%	9.6%
Return on Average Common Equity	(0.3)%	3.8%	6.0%	10.5%	10.6%	13.9%
Dividend Payout Ratio	—	168%	109%	66%	68%	53%
Capital Ratio (percents):						
Short-Term and Long-Term Debt	44.3	42.2	40.9	45.0	36.9	36.6
Preferred Stock and Other Equity	1.4	1.4	1.4	1.7	2.1	2.2
Common Equity	54.3	56.4	57.7	53.3	61.0	61.2
	100.0	100.0	100.0	100.0	100.0	100.0

Notes: (1) Excludes ShoreMaster $19.7 million asset impairment charge in 2010.
(2) See note 15 to consolidated financial statements in 2010 Annual Report on Form 10-K.

SELECTED ELECTRIC OPERATING DATA	2010	2009	2008	2007	2006	2005
Revenues (thousands)						
Residential	$ 101,588	$ 98,164	$ 97,567	$ 92,254	$ 86,950	$ 83,740
Commercial and Farms	118,178	109,914	113,307	111,960	101,895	100,677
Industrial	75,628	69,790	74,879	68,648	65,370	61,235
Sales for Resale	23,197	15,762	27,236	25,640	25,965	46,397
Other Electric	21,722	21,036	27,086	25,089	26,051	21,462
Total Electric	$ 340,313	$ 314,666	$ 340,075	$ 323,591	$ 306,231	$ 313,511
Kilowatt-Hours Sold (thousands)						
Residential	1,273,122	1,296,779	1,257,641	1,218,026	1,170,841	1,162,765
Commercial and Farms	1,570,611	1,592,870	1,576,230	1,515,635	1,453,664	1,428,059
Industrial	1,350,065	1,286,092	1,339,726	1,321,249	1,297,287	1,233,948
Other	68,950	68,636	68,310	68,921	69,062	69,663
Total Retail	4,262,748	4,244,377	4,241,907	4,123,831	3,990,854	3,894,435
Sales for Resale	961,028	1,407,414	2,682,629	1,648,841	2,778,460	2,778,431
Total	5,223,776	5,651,791	6,924,536	5,772,672	6,769,314	6,672,866
Annual Retail Kilowatt-Hour Sales Growth	0.4%	0.1%	2.9%	3.3%	2.5%	3.2%
Heating Degree Days	8,631	9,516	9,752	9,050	8,260	8,656
Cooling Degree Days	484	256	330	482	517	423
Average Revenue Per Kilowatt-Hour						
Residential	7.98¢	7.57¢	7.76¢	7.57¢	7.43¢	7.20¢
Commercial and Farms	7.52¢	6.90¢	7.19¢	7.39¢	7.01¢	7.05¢
Industrial	5.60¢	5.43¢	5.59¢	5.20¢	5.04¢	4.96¢
All Retail	7.06¢	6.65¢	6.78¢	6.71¢	6.54¢	6.39¢
Customers						
Residential	101,797	101,804	101,600	101,750	101,657	101,176
Commercial and Farms	26,406	26,435	26,557	26,500	26,343	26,211
Industrial	43	40	42	42	42	44
Other	1,010	1,028	1,069	1,050	1,028	1,035
Total Electric Customers	129,256	129,307	129,268	129,342	129,070	128,466
Residential Sales						
Average Kilowatt-Hours Per Customer (3)	12,693	12,947	12,449	12,100	11,706	11,749
Average Revenue Per Residential Customer	$ 1,003.50	$ 994.16	$ 976.37	$ 893.01	$ 862.99	$ 776.48
Depreciation Reserve (thousands)						
Electric Plant in Service	$ 1,332,974	$ 1,313,015	$ 1,205,647	$ 1,028,917	$ 930,689	$ 910,766
Depreciation Reserve	$ 476,188	$ 446,008	$ 421,177	$ 401,006	$ 388,254	$ 374,786
Reserve to Electric Plant (percent)	35.7	34.0	34.9	39.0	41.7	41.2
Composite Depreciation Rate (percent)	3.01	2.90	2.81	2.78	2.82	2.74
Peak Demand and Net Generating Capability						
Peak Demand (kw)	817,130	800,488	786,560	704,940	690,243	665,064
Net Generating Capability (kw): (4)						
Steam	551,600	539,466	549,925	549,800	549,350	559,175
Wind	138,000	138,500	41,383	—	—	—
Combustion Turbines	112,400	116,550	131,045	132,744	137,595	135,701
Hydro	3,700	3,765	3,742	4,338	4,294	4,244
Total Owned Generating Capability	805,700	798,281	726,095	686,882	691,239	699,120

Notes: (3) Based on average number of customers during the year.
(4) Measurement of summer net dependable capacity under MISO beginning in 2009.

OTTER TAIL CORPORATION

ELECTRIC

Otter Tail Power Company
Electric utility
Fergus Falls, MN / 1907
Chuck MacFarlane
681 employees
www.otpco.com

WIND ENERGY

DMI Industries, Inc.
Wind tower/heavy steel manufacturer
Fargo, ND / 1990
Stefan Nilsson
623 employees
www.dmiindustries.com

E.W. Wylie Corporation
Flatbed and specialized contract, brokerage and common carrier
West Fargo, ND / 1999
Brian Gast
215 employees
51 owner/operators
www.wylietrucking.com

MANUFACTURING & INFRASTRUCTURE

MANUFACTURING

BTD Manufacturing, Inc.
Metal fabricator
Detroit Lakes, MN / 1995
Paul Gintner
647 employees
www.btdmfg.com

ShoreMaster, Inc.
Waterfront equipment manufacturer
Fergus Falls, MN / 2002
Don Hurley
218 employees
www.shoremaster.com

T.O. Plastics, Inc.
Custom plastic parts manufacturer
Clearwater, MN / 2001
Mike Vallafskey
164 employees
www.toplastics.com

CONSTRUCTION

Aevenia, Inc.
Energy and electrical construction
Moorhead, MN / 1992
Scott Edwards
207 employees
www.aevenia.com

Foley Company
Water, wastewater, power and industrial construction
Kansas City, MO / 2003
Chris Callegari
284 employees
www.foleycompany.com

PLASTICS

Northern Pipe Products, Inc.
PVC pipe manufacturer
Fargo, ND / 1995
Steve Laskey
75 employees
www.northernpipe.com

Vinyltech Corporation
PVC pipe manufacturer
Phoenix, AZ / 2000
Steve Laskey
48 employees
www.vtpipe.com

FOOD INGREDIENT PROCESSING

Idaho Pacific Holdings, Inc.
Dehydrated potato processor
Ririe, ID / 2004
Wally Browning
407 employees
www.idahopacific.com

HEALTH SERVICES

DMS Health Technologies, Inc.
Diagnostic imaging services and equipment sales
Fargo, ND / 1993
Paul Wilson
274 employees
www.dmshealthtechnologies.com

CHART LEGEND

Company Name
Company description
Location of headquarters / Year acquired
Operating company leader
Full-time employees
Web site address

10-K

OTTER TAIL CORPORATION
FORM 10-K FOR THE
FISCAL YEAR ENDING
DECEMBER 31, 2010

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, 2010**

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

Commission File Number 0-53713

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] No [ ]

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [X] Accelerated Filer [ ] Non-Accelerated Filer [ ] *(Do not check if a smaller reporting company)* Smaller Reporting Company [ ]

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

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 30, 2010 was **$684,989,459.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **36,002,739 Common Shares ($5 par value) as of February 15, 2011.**

Documents Incorporated by Reference: **Proxy Statement for the 2011 Annual Meeting-Portions incorporated by reference into Part III**

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. References in this report to Otter Tail Corporation and the Company refer, for periods prior to July 1, 2009, to the corporation that was the registrant prior to the reorganization, and, for periods after the reorganization, to the new parent holding company, in each case including its consolidated subsidiaries, unless otherwise indicated or the context otherwise requires. The Company's executive offices are located at 215 South Cascade Street, P.O. Box 496, Fergus Falls, Minnesota 56538-0496 and 4334 18th Avenue SW, Suite 200, P.O. Box 9156, Fargo, North Dakota 58106-9156. Its telephone number is (866) 410-8780.

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

Otter Tail Corporation and its subsidiaries conduct business in all 50 states and in international markets. The Company had approximately 3,901 full-time employees at December 31, 2010. In the fourth quarter of 2010, the Company realigned its business structure and defined its operating segments to be consistent with its business strategy and the reporting and review process used by the corporation's chief operating decision makers, resulting in the following seven operating segments: Electric, Wind Energy, Manufacturing, Construction, Plastics, Health Services and Food Ingredient Processing. The chart below indicates the companies included in each segment.

ELECTRIC	WIND ENERGY	MANUFACTURING	CONSTRUCTION	PLASTICS	HEALTH SERVICES	FOOD INGREDIENT PROCESSING
Otter Tail Power Company	DMI Industries, Inc.	BTD Manufacturing, Inc.	Foley Company	Northern Pipe Products, Inc.	DMS Health Technologies, Inc.	Idaho Pacific Holdings, Inc.
Otter Tail Energy Services Company	E.W. Wylie Corporation	ShoreMaster, Inc.	Aevenia, Inc.	Vinyltech Corporation		
		T.O. Plastics, Inc.				

All information in this report, including comparative financial information, has been revised to reflect the realignment 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 now includes Otter Tail Energy Services Company (OTESCO), which provides technical and engineering services and energy efficient lighting primarily in North Dakota and Minnesota. OTESCO's activities were included in Other Business Operations prior to the realignment of the Company's business segments.
- **Wind Energy** consists of two businesses: a steel fabrication company primarily involved in the production of wind towers sold in the United States and Canada, with manufacturing facilities in North Dakota, Oklahoma and Ontario, Canada, and a trucking company headquartered in West Fargo, North Dakota, specializing in flatbed and heavy-haul services and operating in 49 states and six Canadian provinces. Prior to the realignment of the Company's business segments, the wind tower production company was included in Manufacturing and the trucking company was included in Other Business Operations.
- **Manufacturing** consists of businesses in the following manufacturing activities: contract machining, metal parts stamping and fabrication, and production of waterfront equipment, material and handling trays and horticultural containers. These businesses have manufacturing facilities in Florida, Illinois, Minnesota and Missouri and sell products primarily in the United States.
- **Construction** consists of businesses involved in residential, commercial and industrial electric contracting and construction of fiber optic and electric distribution systems, water, wastewater and HVAC systems primarily in the central United States. Construction operations were included in Other Business Operations prior to the realignment of the Company's business segments.
- **Plastics** consists of businesses producing polyvinyl chloride (PVC) pipe in the upper Midwest and Southwest regions of the United States.
- **Health Services** consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging equipment and technical staff to various medical institutions located throughout the United States.
- **Food Ingredient Processing** consists of Idaho Pacific Holdings, Inc. (IPH), which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries. Approximately 18% of IPH's sales in 2010 were to customers outside 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 continues to investigate and evaluate organic growth and strategic acquisition opportunities as well as divestiture opportunities which will allow it to raise internal capital to support its future capital expenditure plans and adjust its overall risk profile.

The Company considers the following guidelines when reviewing potential acquisition candidates:

- Emerging or middle market company;
- Proven entrepreneurial management team that will remain after the acquisition;
- Preference for 100% ownership of the acquired company;
- Products and services intended for commercial rather than retail consumer use; and
- The potential to provide immediate earnings and future growth.

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 35 through 49 of this Annual Report on Form 10-K.

(b) Financial Information about Industry Segments

The Company is engaged in businesses that have been classified into seven segments: Electric, Wind Energy, Manufacturing, Construction, Plastics, Health Services and Food Ingredient Processing. Financial information about the Company's segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 63 through 66 of this Annual Report on Form 10-K.

(c) Narrative Description of Business

ELECTRIC

General

Electric consists of two businesses: OTP and OTESCO. OTP, headquartered in Fergus Falls, Minnesota, provides electricity to more than 129,000 customers in a 50,000 square mile area of Minnesota, North Dakota and South Dakota. OTESCO, headquartered in Fergus Falls, Minnesota, provides technical and engineering services and energy efficient lighting primarily in North Dakota and Minnesota. The Company derived 30%, 30% and 26% of its consolidated operating revenues from the Electric segment for each of the three years ended December 31, 2010, 2009 and 2008, respectively.

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

State	2010	2009
Minnesota	48.9%	49.1%
North Dakota	41.2	41.5
South Dakota	9.9	9.4
Total	100.0%	100.0%

The territory served by OTP is predominantly agricultural. The aggregate population of OTP's retail electric service area is approximately 230,000. In this service area of 423 communities and adjacent rural areas and farms, approximately 130,900 people live in communities having a population of more than 1,000, according to the 2000 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,527); Fergus Falls, Minnesota (13,471); and Bemidji, Minnesota (11,917). As of December 31, 2010, OTP served 129,256 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	2010	2009
Commercial	36.4%	36.8%
Residential	31.3	32.8
Industrial	23.3	23.3
All Other Sources	9.0	7.1
Total	100.0%	100.0%

Wholesale electric energy kilowatt-hour (kwh) sales were 18.4% of total kwh sales for 2010 and 24.9% for 2009. Wholesale electric energy kwh sales decreased by 31.7% between the years while revenue per kwh sold increased by 20.7%. 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, 2010 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants	
Big Stone Plant	256,500 kW
Coyote Station	150,000
Hoot Lake Plant	145,100
Total Baseload Net Plant	551,600 kW
Combustion Turbine and Small Diesel Units	112,400 kW
Hydroelectric Facilities	3,700 kW
Owned Wind Facilities (rated at nameplate)	
Luverne Wind Farm (33 turbines)	49,500 kW
Ashtabula Wind Center (32 turbines)	48,000
Langdon Wind Center (27 turbines)	40,500
Total Owned Wind Facilities	138,000 kW

The baseload net plant capacity for Big Stone Plant and Coyote Station constitutes OTP's ownership percentages of 53.9% and 35%, respectively. OTP owns 100% of the Hoot Lake Plant. During 2010, OTP generated about 81% of its retail kwh sales and purchased the balance.

In addition to the owned facilities described above OTP had the following purchase power agreements in place on December 31, 2010:

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)	
MP (50,000 kW ends April 30, 2011)	
WEPCO (35,000 kW ends May 31, 2011)	
WEPCO (Begins June 1, 2011)	50,000 kW
GRE	50,000
WAPA	5,800
Total Purchased Power	105,800 kW

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 (PRCs) to meet its monthly weather normalized forecast demand, plus a reserve obligation. OTP met its MISO obligation for all months in 2010. MISO is currently in discussions with the Federal Energy Regulatory Commission (FERC) and stakeholders to initiate changes to its Resource Adequacy Construct. Any changes would be effective beginning June 1, 2012. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2011 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 2010 and 2009:

	2010		2009	
Sources	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated
Subbituminous Coal	2,499,132	61.2%	2,186,145	63.0%
Lignite Coal	1,060,954	26.0	856,359	24.7
Wind and Hydro	478,230	11.7	391,032	11.3
Natural Gas and Oil	45,116	1.1	33,017	1.0
Total	4,083,432	100.0%	3,466,553	100.0%

OTP has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Peabody COALSALES, LLC	Wyoming subbituminous	December 31, 2012
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	May 4, 2016
Hoot Lake Plant	Cloud Peak Energy Resources LLC	Wyoming subbituminous	December 31, 2011

The contract with Dakota Westmoreland Corporation has a 5 to 15-year renewal option, subject to certain contingencies. The Coyote Station owners informed Dakota Westmoreland Corporation on May 4, 2010 that they did not intend to exercise their right to extend the current contract when it expires on May 4, 2016. OTP is negotiating with a supplier for the purchase of additional coal for Hoot Lake Plant in 2011 and for 2012 requirements, and anticipates signing a confirmation letter before April 2011. 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 coal consumed (including handling charges to the plant sites) per million British Thermal Units for each of the three years 2010, 2009 and 2008 was $1.813, $1.726 and $1.678, 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:

		2010		2009	
Rates	Regulation	% of Electric Revenues	% of kwh Sales	% of Electric Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	43.2%	39.9%	42.4%	37.6%
ND Retail Sales	ND Public Service Commission	36.5	33.4	35.8	30.2
SD Retail Sales	SD Public Utilities Commission	8.8	8.3	8.1	7.3
Transmission & Wholesale	Federal Energy Regulatory Commission	11.5	18.4	13.7	24.9
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 lower rates for residential demand control, general service time of use and time of day, real-time pricing and controlled service and in North Dakota and South Dakota for bulk interruptible rates. Each of these specialized rates is designed to improve efficient use of OTP resources, while giving customers more control over the size of their electric bill. In all three states, OTP has approved tariffs 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. In North Dakota and South Dakota, OTP also credits certain margins from wholesale sales to the fuel and purchased power adjustment. The adjustments for fuel and purchased power costs are presently based on a two month moving average in Minnesota and by the FERC, a three month moving average in South Dakota and a four month moving average in North Dakota. These adjustments are applied to the next billing period after becoming applicable. These adjustments also include an over or under recovery mechanism, which is calculated on an annual basis in Minnesota and on a monthly basis in North Dakota and South Dakota.

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

Minnesota

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

The Minnesota Office of Energy Security (MNOES), part of the Minnesota Department of Commerce (MNDOC), is responsible for investigating all matters subject to the jurisdiction of the MNDOC or the MPUC, and for the enforcement of MPUC orders. Among other things, the MNOES is authorized to collect and analyze data on energy and 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 MNOES acts as a state advocate in matters heard before the MPUC. The MNOES 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.

2007 General Rate Case Filing—In an order issued by the MPUC on August 1, 2008, OTP was granted an increase in Minnesota retail electric rates of $3.8 million, or approximately 2.9%, which went into effect in February 2009. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% was in effect from November 30, 2007 through January 31, 2009. OTP refunded Minnesota customers the difference between interim and final rates, with interest, in March 2009.

2010 General Rate Case Filing—OTP filed a general rate case on April 2, 2010, seeking an 8.01% increase with a 3.8% interim rate request. On May 27, 2010, the MPUC issued an order accepting the filing, suspending rates and setting interim rates. The MPUC approved a 3.8% interim rate increase to be effective with customer usage on and after June 1, 2010. OTP expects oral arguments before the MPUC and deliberations to take place in late March 2011 and the MPUC to issue an order by April 25, 2011. If final rates are lower than interim rates, OTP will refund Minnesota customers the difference, with interest.

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. A statewide energy conservation goal of 1.5% of the historical three-year weather normalized average megawatt hour (mwh) retail sales was set for 2010. OTP filed its plan to achieve these goals on June 1, 2008 for implementation in 2009 and 2010. The MNOES 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 MNOES orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under Minnesota's Conservation Improvement Programs through the use of an annual recovery mechanism approved by the MPUC.

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 January 15, 2009 the MPUC approved OTP's 2006-2020 IRP in its entirety. On June 2, 2009 the MPUC issued an order denying reconsideration, thus finalizing the IRP. The 2006-2020 IRP included new renewable wind generation, significant demand-side management including conservation, new baseload (which included the cancelled Big Stone II power plant), natural gas-fired peaking plants and wholesale energy purchases. Megawatt (MW) capacity additions approved in accordance with Minnesota rules in the 2006-2020 IRP, excluding baseload generation for the cancelled Big Stone II, were as follows:

Resource	Approved
Natural Gas	200 MW
Wind	280 MW
Demand-Side Management	100 MW

On September 24, 2009 the MPUC issued an order granting OTP's request to extend its most recent IRP filing deadline to July 1, 2010. On June 25, 2010 OTP filed its 2011-2025 IRP with the MPUC. The MNOES 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-Side Management	70 MW
Wind	50 MW

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. It has effectively prohibited the building of new nuclear facilities. 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 rate recovery therefrom, 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. On October 8, 2009, the MPUC established an estimate of the range of costs of future carbon dioxide (CO_2) regulation to be used in modeling analyses for resource plans. The MPUC is required to annually update these estimates. The current estimate is $9 to $34/ton of CO_2.

Minnesota has a renewable energy standard which requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP has sufficient renewable energy resources available and in service to comply with the required 2016 level of the Minnesota renewable energy standard. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

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

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

Transmission Cost Recovery (TCR) Rider—In addition to the Renewable Resource Cost Recovery Rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a CON proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or otherwise deemed eligible by the MPUC. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010 OTP's TCR rider rate is reflected on Minnesota customer electric service statements at $0.00039 per kwh plus $0.035 per kW for large general service customers and $0.00007 per kwh for controlled service customers, $0.00025 per kwh for lighting customers, and $0.00057 per kwh for all other customers. OTP has requested recovery of its transmission investments currently being recovered through OTP's Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. The transmission investments will continue to be recovered through OTP's Minnesota TCR rider rate until the MPUC makes a decision on OTP's general rate case. OTP filed a request for an update to its Minnesota TCR rider rate on October 5, 2010.

Power Plant Siting and Transmission Line Routing—Pursuant to the Minnesota Power Plant Siting Act, the MPUC has been granted the authority to regulate the siting in Minnesota of large electric generating facilities in an orderly manner compatible with environmental preservation and the efficient use of resources. To that end, the MPUC is empowered, after an environmental impact study is conducted by the MNDOC and the Office of Administrative Hearings conducts contested case hearings, to select or designate sites in Minnesota for new electric power generating plants (50,000 kW or more) and routes for transmission lines (100 kilovolt (kV) or more) and to certify such sites and routes as to environmental compatibility.

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

Big Stone II Project—OTP and a coalition of six other electric providers filed an application for a CON for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. On January 15, 2009, the MPUC approved, by a vote of 5-0, a motion to grant the CON and Route Permit for the Minnesota portion of the Big Stone II transmission line.

The MPUC granted the CON subject to a number of additional conditions, including but not limited to: (1) fulfilling various requirements relating to renewable energy goals, energy efficiency, community-based energy development projects and emissions reduction; (2) that the generation plant be built as a "carbon capture retrofit ready" facility; (3) that the applicants report to the MPUC on the feasibility of building the plant using ultra-supercritical technology; and (4) that the applicants achieve specific limits on construction costs at $3,000/kW and CO_2 costs at $26/ton.

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

Following OTP's September 11, 2009 withdrawal from the Big Stone II project and the remaining Big Stone II participants' November 2, 2009 cancellation of the project, the suitability of the route permits and easements obtained by OTP as a MISO transmission owner for other interconnection customers backfilling through the MISO interconnection process into the Big Stone area continues to be evaluated.

On December 14, 2009 OTP filed a request with the MPUC for deferred regulatory accounting treatment for the costs incurred related to the cancelled Big Stone II plant. OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010, and thereafter requested withdrawal of its December 14, 2009 request for deferred accounting as duplicative of the issues presented in the rate case. If the MPUC eventually denies recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed unrecoverable.

On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone transmission facilities. The request asks to extend the deadline for filing a CON for these transmission facilities until March 17, 2013.

Capacity Expansion 2020 (CapX2020)—Planning studies have shown there will be significant electric load growth and more transmission will be necessary for renewable energy in the coming decade. The study resulted in a joint transmission planning initiative among eleven utilities that own transmission lines in Minnesota and the surrounding region, called CapX2020—capacity expansion by 2020. On August 16, 2007 the eleven CapX2020 utilities asked the MPUC to determine the need for three 345-kV transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years.

Fargo-Monticello 345 kV Project, Brookings-Southeast Twin Cities 345 kV Project and Twin Cities-LaCrosse 345 kV Project—On April 16, 2009 the MPUC granted CONs for the three 345 kV Group 1 CapX2020 line projects (Fargo-Monticello, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse).

The route permit application for the Monticello to St. Cloud portion of the Fargo project was filed in April 2009. The MPUC approved the route permit application and issued a written order on July 12, 2010. Required permits from the Minnesota Department of Transportation, Minnesota Department of Natural Resources and the U.S. Army Corps of Engineers were received in 2010. A Transmission Capacity Exchange Agreement, allocating transmission capacity rights to owners across the Monticello to St. Cloud portion of the project, was accepted by the FERC in the third quarter of 2010.

The Minnesota route permit application for the St. Cloud to Fargo portion of the Fargo project was filed on October 1, 2009. The MPUC is expected to make a determination on the route permit application in the second quarter of 2011. Minnesota State Environmental Impact Statement (EIS) scoping meetings were held in September 2010 and public hearings were held in November 2010.

The route permit application for the Brookings project was filed in the fourth quarter of 2008. On July 15, 2010 the MPUC voted to approve most of the Brookings route permit application. On September 15, 2010 the MPUC approved a route permit for five of six project line segments, with the exception of the line segment that crosses the Minnesota River. Additional Evidentiary Hearings were held regarding the line segment crossing the Minnesota River, and the Administrative Law Judge issued a report in December of 2010. The MPUC approved the final line segment for the project on February 3, 2011.

Bemidji-Grand Rapids 230 kV Project—OTP serves as the lead utility for the CapX2020 Bemidji-Grand Rapids 230-kV project, which has an expected in-service date of late 2012 or early 2013. The MPUC approved the CON for this project on July 9, 2009. A route permit application was filed with the MPUC in the second quarter of 2008 for the Bemidji-Grand Rapids project. On October 28, 2010 the MPUC approved the route permit application for the project. The joint state and federal EIS was published by the federal agencies on September 7, 2010, and the project's Transmission Capacity Exchange Agreement was accepted and approved by the FERC in the third quarter of 2010.

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 2011. OTP intends to file its 2011 capital structure petition by the end of March 2011.

Big Stone Air Quality Control System (AQCS) Request for Advance Determination of Prudence—Minnesota law authorizes a public utility to petition the MPUC for an advance determination of prudence for a project undertaken to comply with federal or state air quality standards of states in which the utility's electric generation facilities are located, if the project has an expected jurisdictional cost to Minnesota ratepayers of at least $10 million. On January 14, 2011 OTP filed a petition for its proposed Big Stone AQCS. The MPUC is required to make a final determination on the petition within ten months of its filing date. On January 18, 2011 the MPUC issued a notice seeking procedural comments on the appropriate process for the case, including whether it should be set for contested case hearing and what the scope of such hearing should be. Written comments are to be filed with the MPUC by February 14, 2011 and reply comments by February 25, 2011.

North Dakota

OTP is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities and other matters. The NDPSC periodically performs audits of gas and electric utilities over which it has rate setting jurisdiction to determine the reasonableness of overall rate levels. In the past, these audits have occasionally resulted in settlement agreements adjusting rate levels for OTP. The North Dakota Energy Conversion and Transmission Facility Siting Act grants the NDPSC the authority to approve sites in North Dakota for large electric generating facilities and high voltage transmission lines. This Act is similar to the Minnesota Power Plant Siting Act described above and applies to proposed new electric power generating plants exceeding 60,000 kW and proposed new transmission lines with a design in excess of 115 kV. OTP is required to submit a ten-year plan to the NDPSC annually.

The NDPSC reserves the right to review the issuance of stocks, bonds, notes and other evidence of indebtedness of a public utility. However, the issuance by a public utility of securities registered with the SEC is expressly exempted from review by the NDPSC under North Dakota state law.

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

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

In a proceeding that was combined with OTP's general rate case, the NDPSC reviewed whether to move the costs of the projects currently being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to $0.00369 for the period from December 1, 2009 until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA (which includes cost recovery for OTP's investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010. Approval for implementation of an updated NDRRA was received in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the NDRRA to $0.00473 per kwh plus $0.212 per kW for the large general service class, and $0.00551 per kwh for all other customer classes. The 2010 NDRRA was established with an expected recovery of $15.8 million over the period September 1, 2010 to March 31, 2012. The 2010 NDRRA will be in effect until the NDPSC sets another updated NDRRA.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP requested recovery of such costs in its general rate case filed in November 2008 and was granted recovery of such costs by the NDPSC in its November 25, 2009 order. OTP anticipates filing a request for an initial North Dakota TCR rider with the NDPSC in the first quarter of 2011.

MISO-Related Costs—In February 2005, OTP filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the fuel clause adjustment (FCA) in North Dakota. The NDPSC granted interim recovery through the FCA in April 2005, but conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between OTP and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, OTP refunded $493,000 of MISO schedule 16 and 17 costs collected through the FCA from April 2005 through July 2007 to North Dakota customers beginning in October 2007 and ending in January 2008. OTP deferred recognition of these costs plus $330,000 in MISO schedule 16 and 17 costs incurred from August 2007 through December 2008 and requested recovery of these deferred costs in its general rate case filed in North Dakota in November 2008. OTP began amortizing its deferred MISO schedule 16 and 17 costs in North Dakota over a 36-month period beginning in December 2009 in conjunction with the implementation of rates approved by the NDPSC in its November 25, 2009 order. As of December 31, 2010 the balance of OTP's deferred MISO schedule 16 and 17 costs was $717,000. Base rate recovery for on-going MISO schedule 16 and 17 costs was also approved by the NDPSC in its November 25, 2009 order.

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

On December 14, 2009 OTP filed a request with the NDPSC for deferred regulatory accounting treatment for its costs incurred related to cancelled Big Stone II project. In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC Advocacy Staff, OTP and the North Dakota Large Industrial Energy Group, which had intervened. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excludes $2,612,000 of project transmission-related costs) was determined to be $10,080,000, of which $4,064,000 represents North Dakota's jurisdictional share.

The North Dakota portion of Big Stone II generation costs is being recovered over a 36 month period beginning August 1, 2010.

The portion of Big Stone II costs incurred by OTP related to transmission is $2,612,000, of which $1,053,000 represents North Dakota's jurisdictional share. OTP transferred the North Dakota Share of Big Stone II transmission costs to Construction Work in Progress (CWIP), with such costs subject to Allowance for Funds Used During Construction (AFUDC) continuing from September 2009. If construction of all or a portion of the transmission facilities commences within three years of the NDPSC order approving the settlement agreement, the North Dakota portion of Big Stone II transmission costs and accumulated AFUDC shall be included in the rate base investment for these future transmission facilities. If construction is not commenced on any of the transmission facilities within three years of the NDPSC order approving the settlement agreement, OTP may petition the NDPSC to either continue accounting for these costs as CWIP or to commence recovery of such costs.

CapX2020 Requests for Advance Determination of Prudence and Certificate of Public Convenience and Necessity (CPNC)—On October 5, 2009 OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of four Group 1 projects (Fargo-Monticello, Brookings-Southeast Twin Cities, and Bemidji-Grand Rapids). 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 advance determination of prudence 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-Southeast Twin Cities project and its associated impact on North Dakota. Permitting activities for the North Dakota portion of the project began in 2010 with the filing of a CPCN on October 8, 2010. The NDPSC approved the CPCN in early January 2011. A Certificate of Corridor Compatibility Application was filed with the NDPSC in December 2010. Additional permitting related to transmission line routing will be required in North Dakota with filings expected in 2011.

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. OTP is not currently subject to the jurisdiction of the SDPUC with respect to the issuance of securities. Under the South Dakota Energy Facility Permit Act, the SDPUC has the authority to approve sites in South Dakota for large energy conversion facilities (100,000 kW or more) and transmission lines with a design of 115 kV or more.

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

2010 General Rate Case Filing—On August 20, 2010 OTP filed a general rate case with the SDPUC requesting an overall revenue increase of approximately $2.8 million, or just under 10.0%, which includes, among other things, recovery of investments and expenses related to renewable resources. On September 28, 2010 the SDPUC suspended OTP's proposed rates for a period of 180 days to allow time to review OTP's proposal. The SDPUC ordered the assessment of a filing fee up to $125,000 to cover a portion of its expenses to review the filing. South Dakota statutes allow OTP to implement proposed rates 180 days after the date of filing a general rate case even if the SDPUC has not approved its initial 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 also 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. A hearing before the SDPUC is expected in April, 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.

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. If the SDPUC eventually denies recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed unrecoverable.

CapX2020 Brookings-Southeast Twin Cities 345 kV Project—An application for a South Dakota facility route permit was filed with the SDPUC on November 22, 2010. The SDPUC conducted a public hearing in January 2011 and a South Dakota route permit is expected to be approved in the second quarter of 2011.

Energy Efficiency Plan—On January 4, 2007 the SDPUC encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use. On July 28, 2008 the SDPUC approved OTP's energy efficiency plan for South Dakota customers. The plan is being implemented with program costs, carrying costs and a financial incentive being recovered through an approved rider.

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

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.

On October 30, 2009, OTP filed a request with the FERC for approval of various transmission infrastructure investment incentives and proposed revisions to OTP's transmission formula rate under Attachment O of the MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff. OTP requested recovery of (1) 100% of prudently incurred CWIP in rate base, and (2) 100% prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP's control (Abandoned Plant Recovery). In addition, OTP proposed changes to its Attachment O to recover its revenue requirement under a forward-looking formula rate using projected test period cost inputs with an annual true-up, rather than a formula rate based on historic test period data. On December 30, 2009, the FERC issued an order approving OTP's request for 100% CWIP recovery and 100% Abandoned Plant Recovery for OTP's proposed investment in the CapX2020 transmission projects (Fargo project, Bemidji project and Brookings project) to be effective January 1, 2010. In addition, the FERC conditionally approved OTP's request for using a forward looking Attachment O under the MISO Tariff to be effective January 1, 2010 pending the completion of a compliance filing.

In January 2009, the MISO and its stakeholders initiated a stakeholder process to address the unintended consequences of the MISO's cost allocation for generator interconnection project network upgrades. Under the "then effective" cost allocation, the network transmission upgrade costs needed for generator interconnection projects were borne equally between the interconnecting generator and the local utility without any regard for whether the local utility benefitted from the generator. In the case of OTP, this was significant given the amount of generation seeking to interconnect to the OTP system exceeded its load serving obligations by more than ten times its needs. To address this inequity, in July 2009, a filing was made at the FERC. In October 2009, the FERC approved an interim cost allocation assigning most of the network upgrade costs to the generators, with the assumption that the generators could pass those costs directly to the customers who benefit from the projects. The October 2009 order required the MISO and its transmission owners to come back in July 2010 with a long-term cost-allocation proposal. On July 15, 2010 a filing was made to (1) make permanent the interim cost allocation for transmission network upgrades associated with generator interconnections and (2) establish a new category of transmission projects called Multi-Value Projects (MVPs) that have a regional impact and are part of a regional plan and that have broad benefits to the MISO membership. On December 16, 2010 the FERC approved the July 15 filing. In the MISO, there now exist four types of cost allocation methodologies (1) reliability-driven transmission upgrades, (2) market efficiency transmission upgrades, (3) transmission network upgrades associated with generator interconnection projects, and (4) MVPs.

Revenue Sufficiency Guarantee (RSG) Charges—Since 2006, OTP has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdrew energy from the market or engaged in financial-only, virtual sales of energy into the market, or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC's orders are on review before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). As of the date of this report OTP does not have a known liability. The Company continues to monitor the proceedings but cannot predict the outcome.

MEMA

OTP is a member of the Mid-Continent Energy Marketers Association (MEMA) which is an independent, non-profit trade association representing entities involved in the marketing of energy or in providing services to the energy industry. MEMA operates in the Mid-Continent Area Power Pool (MAPP), MISO, Southwest Power Pool, PJM Interconnection, LLC and Southeast regions and was formed in 2003 as a successor organization of the Power and Energy Market of MAPP. Power pool sales are conducted continuously through MEMA in accordance with schedules filed by MEMA with the FERC.

MRO

OTP is a member of the Midwest Reliability Organization (MRO). The MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO began operations in 2005 and is one of eight regional entities in North America operating under authority from regulators in the United States and Canada through a delegation agreement with the North American Electric Reliability Corporation (NERC). The MRO is responsible for: (1) developing and implementing reliability standards, (2) enforcing compliance with those standards, (3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity, and (4) providing an appeals and dispute resolution process.

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

MISO

OTP is a member of the MISO. As the transmission provider and security coordinator for the region, the MISO seeks to optimize the efficiency of the interconnected system, provide regional solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions. The MISO covers a broad region containing all or parts of 13 states and the Canadian province of Manitoba. The MISO began operational control of OTP's transmission facilities above 100 kV on February 1, 2002 but OTP continues to own and maintain its transmission assets.

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

The MISO Ancillary Services Market (ASM) commenced on January 6, 2009. The market facilitates the provision of Regulation, Spinning Reserve and Supplemental Reserves. The ASM integrates the procurement and use of regulation and contingency reserves with the existing Energy Market. OTP has actively participated in the market since its commencement.

In December 2008 pursuant to the provisions of the MISO Transmission Owners Agreement, OTP sent MISO a letter of intent to withdraw from MISO on or after December 31, 2009. This procedural step was taken to allow OTP the earliest available opportunity to withdraw from MISO if its concerns about the unintended consequences produced by the MISO Tariff, which imposed a disproportionate allocation of charges to its customers, attributable to the allocation of costs for transmission network upgrades, cannot be equitably resolved. Withdrawal from MISO would require OTP to either secure replacement of and/or self-provide the services currently provided by MISO. In December 2009, OTP provided MISO notice that it was reaffirming its notice of intent to withdraw given the on-going uncertainty around the potential for large negative impacts on OTP customers. In November 2010, OTP confirmed that its letter of intent to withdraw remained 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. OTP may also face competition as the restructuring of the electric industry evolves.

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, 2010 OTP invested approximately $15.6 million in environmental control facilities. The 2011 construction budget includes approximately $5.6 million for environmental equipment for existing facilities.

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

The primary fuels burned by OTP's steam generating plants are North Dakota lignite coal and western subbituminous coal. Electrostatic precipitators have been installed at the principal units at the Hoot Lake Plant. Hoot Lake Plant unit 1 turbine generator, which is the smallest of the three coal-fired units at Hoot Lake Plant, was retired as of December 31, 2005. OTP has retained the unit 1 boiler for use as a source of emergency heat. A fabric filter collects particulates from stack gases on Hoot Lake Plant unit 1. 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.

During the fall 2007 maintenance outage at the Big Stone Plant, the demonstration project Advanced Hybrid™ technology was replaced with a pulse jet baghouse. 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 both the existing Big Stone Plant and Big Stone II. On August 3, 2009 the Sierra Club and Clean Water Action petitioned the EPA to object to certain Title V permit provisions applicable to Big Stone II. The Big Stone Plant Title V permit provisions were unchallenged and Big Stone Plant continues to operate under those provisions. The Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The Coyote Station is equipped with sulfur dioxide (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 will 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.

The national NO_X emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. In order to meet the national NO_X emission standards required at the Hoot Lake Plant unit 2 in 2008, OTP installed low NO_X burners and over-fire air in the first quarter of 2008, enabling the unit to meet the annual average emission rate. The remaining generating units meet EPA NO_X emission regulations. All of OTP's generating facilities met the NO_X standards during 2010.

The EPA Administrator signed the final Interstate Air Quality Rule, also known as the Clean Air Interstate Rule (CAIR), on March 10, 2005. The EPA has concluded that SO_2 and NO_X are the chief emissions contributing to interstate transport of particulate matter less than 2.5 microns (PM2.5). 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 PM2.5 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 ambient air quality 8-hour ozone nonattainment purposes. On July 11, 2007, the U.S. Court of Appeals for the D.C. Circuit vacated CAIR and the CAIR federal implementation plan in its entirety. On December 23, 2008, the court reconsidered and remanded the case for the EPA to conduct further proceedings consistent with the court's prior opinion. On January 16, 2009, the EPA proposed a rule that would stay the effectiveness of CAIR and the CAIR federal implementation plan for sources in Minnesota while the EPA conducts notice-and-comment rulemaking on remand from the D.C. Circuit's decisions in the litigation on CAIR. Remanding the issue to the EPA for further consideration, the court held that the EPA had not adequately addressed errors alleged by Minnesota Power in the EPA's analysis supporting inclusion of Minnesota. Neither the EPA nor any other party sought rehearing of this part of the court's CAIR decision. Public Notice of the final rule staying the implementation of CAIR in Minnesota appeared in the November 3, 2009 Federal Register. On July 6, 2010, the EPA proposed the Transport Rule that essentially would replace the CAIR, but which is proposed to include Minnesota sources due to a finding that Minnesota's emissions contribute to PM2.5 nonattainment in downwind states. As was the case under the CAIR rule, neither North Dakota nor South Dakota sources are slated for regulation by the proposed Transport Rule. The impact on OTP facilities is uncertain at this time since that rule is not yet final. Nonetheless, in anticipation of having to meet CAIR requirements, OTP has already installed NO_X emissions control equipment on both Hoot Lake Plant units 2 and 3.

Air Quality—Hazardous Air Pollutants—The CAA calls for the EPA to study the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and submitted reports to Congress. The CAA required the EPA to make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced it affirmatively decided to regulate mercury emissions from electric generating units, and final rules were published on June 9, 2006 based on a cap and trade approach. On February 8, 2008 the U.S. Court of Appeals for the D.C. Circuit granted petitions for review of the EPA rules and on March 14, 2008 the U.S. Court of Appeals for the D.C. Circuit issued a mandate vacating the EPA final rule regulating utility mercury emissions. The EPA appealed the court's decision to the U.S. Supreme Court, but withdrew its appeal in early 2009. The Supreme Court denied the appeals of other parties to the litigation on February 23, 2009. The EPA rulemaking is slated to proceed under the maximum achievable control technologies (MACT) provision of the CAA Section 112(d) for existing units and Section 112(g) case-by-case MACT provisions for affected new units. The EPA and petitioners have agreed to a schedule where the EPA would adopt final MACT rules that regulate hazardous air pollutants, including mercury, by November 16, 2011. OTP anticipates that the MACT standard may require installation of control technology at its power plants, but until the rule is finalized it cannot determine what will ultimately be required to meet the EPA's final standard or to what extent the EPA rulemaking will impact OTP. OTP currently plans to install mercury control technology at Big Stone Plant when it constructs the AQCS.

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. At this time, OTP cannot determine what, if any, actions will be taken by the EPA.

On November 20, 2006, 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) requirements of the

CAA at the Big Stone Plant with respect to three past plant activities. On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of the Big Stone Plant. The complaint alleged certain violations of the PSD and New Source Performance Standards (NSPS) provisions of the CAA and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the CAA and the South Dakota SIP. The Sierra Club alleged the defendants' actions contributed to air pollution and visibility impairment and increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also sought unspecified civil penalties, including a beneficial mitigation project. The Company believed these claims were without merit and that Big Stone had been and is being operated in compliance with the CAA and the South Dakota SIP. OTP and the co-owners filed a motion to dismiss the citizen's suit. On March 31, 2009, the District Court granted the Big Stone Plant co-owners' motion to dismiss the Sierra Club's citizen suit against the co-owners for alleged violations of the PSD provisions of the CAA, the South Dakota SIP, and the NSPS of the CAA. On April 17, 2009 Sierra Club filed a Motion for Reconsideration of the Amended Memorandum and Order dated April 6, 2009. The District Court denied the motion on July 22, 2009. On July 30, 2009 the Sierra Club appealed the District Court's decision to the U. S. Court of Appeals for the 8th Circuit. On August 12, 2010 the U.S. Court of Appeals for the 8th Circuit affirmed the District Court decision dismissing the Sierra Club's suit against Big Stone Plant. The District Court's decision is now final because Sierra Club did not file a petition for rehearing with the Court of Appeals and did not petition for writ of certiorari with the U.S. Supreme Court by the respective deadlines.

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 PSD and NSPS requirements of the CAA with respect to two past plant activities. The Sierra Club stated that unless the matter is otherwise fully resolved, it intended to file suit in the applicable district courts any time 60 days after the September 22, 2008 letter. As of the date of this report the Sierra Club has not filed suit in the applicable district courts as contemplated in the September 22, 2008 notification. OTP believes that the Big Stone Plant is in material compliance with all applicable requirements of the CAA.

Air Quality—Regional Haze Program—On June 15, 2005 the EPA signed the Regional Haze Best Available Retrofit Technology (BART) rule. The rule requires emissions reductions from designated sources that are deemed to contribute to visibility impairment in Class I air quality areas. The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to emission reduction requirements based on the modeled contribution of the plant emissions to visibility impairment in downwind Class I air quality areas. On November 2, 2009 OTP submitted to DENR its analysis of what control technology should be considered BART for NO_X, SO_2, and particulate matter for the Big Stone Plant.

On January 15, 2010 the DENR provided OTP with a copy of South Dakota's draft proposed Regional Haze State Implementation Plan (SIP). Comments were requested on or before March 16, 2010. South Dakota's draft proposed Regional Haze SIP recommended the sulfur dioxide and particulate matter emission control technology and emission rates that generally followed OTP's BART analysis. The DENR recommended a Selective Catalytic Reduction (SCR) technology for NO_X emission reduction in addition to the OTP-recommended separated over-fire air. At that time OTP estimated the cost of the BART technologies based on the DENR proposal to be approximately $223 million for Big Stone Plant ($120 million OTP share). OTP commissioned Sargent & Lundy to conduct a conceptual design study and prepare more detailed estimated costs for the control technology needed to comply with the South Dakota DENR BART determination. That work was completed by the end of October 2010. Although the studies and evaluations are continuing, the projected project cost is estimated to be approximately $490 million ($264 million OTP share). The DENR proposes to require that BART be installed and operating as expeditiously as practicable, but no later than five years from EPA's approval of the South Dakota Regional Haze SIP. The South Dakota DENR submitted their proposed Regional Haze SIP to the EPA for approval on January 21, 2011.

On January 14, 2011 OTP filed a petition with the MPUC for an advance determination of prudence for the Big Stone Plant AQCS project required under the South Dakota Regional Haze SIP and its associated state rules that establish BART emissions limits for Big Stone Plant. The MPUC has ten months to make a final decision on the petition.

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

Air Quality—Greenhouse Gas Regulation—The issue of global climate change and the connection between global warming and increased levels of CO_2-a greenhouse gas (GHG)-in the atmosphere is receiving significant attention. Combustion of fossil fuels for the generation of electricity is a major stationary source of CO_2 emissions in the United States and globally. OTP is an owner or part-owner of three baseload, coal-fired electricity generating plants and three fuel-oil or natural gas-fired combustion turbine peaking plants with a combined generating capability of 679 MW. In 2010, these plants emitted approximately 4.4 million tons of CO_2.

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

In April 2007, however, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate CO_2 and other GHGs from automobiles as "air pollutants" under the CAA. The Supreme Court sent the case back to the EPA to conduct a rulemaking to determine whether GHG emissions contribute to climate change "which may reasonably be anticipated to endanger public health or welfare." While this case addressed a provision of the CAA related to emissions from motor vehicles, a parallel provision of the CAA applies to stationary sources such as electric generators. The first step in the EPA rulemaking process was the publication of an endangerment finding in the December 15, 2009 Federal Register where the EPA found that CO_2 and five other GHGs—methane, NO_X, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride—threaten public health and the environment.

The EPA's final findings respond to the 2007 U.S. Supreme Court decision that GHGs fit within the CAA's definition of air pollutants. The findings do not in and of themselves impose any emission reduction requirements but rather allowed the EPA to finalize the GHG standards for new light-duty vehicles as part of the joint rulemaking with the Department of Transportation. These standards apply to motor vehicles as of January 2011, which makes GHGs "subject to regulation" under the CAA.

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

The EPA decided to phase in the PSD requirements for GHGs in two steps. Beginning on January 2, 2011, GHG control analysis will be conducted in PSD permit proceedings only if changes at a facility trigger PSD for criteria pollutants and if the proposed change increases GHGs by over 75,000 tons per year of "CO_2e," a measure that converts emissions of each GHG into its carbon dioxide equivalent. Until July 2011 the threshold applies only to facilities currently subject to PSD or Title V permitting. However, as of July 2011, sources emitting more than 100,000 tons per year of CO_2e 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 CO_2e. OTP does not anticipate making modifications at any of its facilities that would trigger PSD requirements, including for GHGs. GHG emissions are not projected to trigger the need for a PSD permit as a result of the Big Stone AQCS Project.

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

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

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

Both NSPS and 111(d) Standards involve development of "standards of performance," but the 111(d) Standard also requires the EPA to consider, "among other factors, remaining useful lives of the sources in the category of sources to which such standard applies." In general, the standards ultimately developed are more stringent for new sources than for existing sources because existing source standards need to consider the issues involved in retrofitting plants considering what can be achieved under their existing design. The standards also need to be capable of attainment across the category of sources regulated by the standard.

While the potential impact of a 111(d) Standard on OTP's facilities is not yet known, standards of performance for GHGs, especially for existing sources, are anticipated to focus on efficiency improvements rather than add-on controls. The cost of efficiency improvements that achieve generation of the same amount of power with less fuel used could be offset in whole or in part by reduced fuel costs.

Several states and regional organizations are also developing, or already have developed, state-specific or regional legislative initiatives to reduce GHG emissions through mandatory programs. In 2007, the state of Minnesota passed legislation regarding renewable energy portfolio standards that will require retail electricity providers to obtain 25% of the electricity sold to Minnesota customers from renewable sources by the year 2025. The Minnesota legislature set a January 1, 2008 deadline for the MPUC to establish an estimate of the likely range of costs of future CO_2 regulation on electricity generation. The legislation also set state targets for reducing fossil fuel use, included goals for reducing the state's output of GHGs, and restricted importing electricity that would contribute to statewide power sector CO_2 emission. The MPUC, in its order dated December 21, 2007, has established an estimate of future CO_2 regulation cost at between \$4/ton and \$30/ton emitted in 2012 and after. Annual updates of the range are required. The MPUC has established the 2009 and 2010 estimates of the likely range of costs of future CO_2 regulation on electricity to be between \$9/ton and \$34/ton.

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

While the eventual outcome of proposed and pending climate change legislation and GHG regulation is unknown, OTP is taking steps to reduce its carbon footprint and mitigate levels of CO_2 emitted in the process of generating electricity for its customers through the following initiatives:

- Supply efficiency and reliability: Between 1990 and 2009, OTP decreased its CO_2 intensity (lbs. of CO_2 /mwh generated) by nearly 23%.
- Conservation: Since 1992 OTP has helped its customers conserve more than 1.2 million mwh of electricity. That is roughly equivalent to the amount of electricity that 110,000 average homes would have used in a year. OTP continues to educate customers about energy efficiency and demand-side management and to work with regulators to develop new programs and measurements. OTP's 2011-2025 IRP calls for an additional 70 MW of conservation impacts by 2025.
- Renewable energy: Since 2002, OTP's customers have been able to purchase 100% of their electricity from wind generation through OTP's TailWinds program. Also, 40.5 MW of purchased power agreement wind projects and 138 MW of owned wind resources were on line by 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 CO_2. OTP is studying the potential for certain methane reduction projects. Methane has a global-warming potential over 20 times that of CO_2. OTP participates in carbon sequestration research through the Plains CO_2 Reduction Partnership (PCOR) through the University of North Dakota's Energy and Environmental Research Center. The PCOR Partnership is a collaborative effort of nearly 100 public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic CO_2 emissions from stationary sources in 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. It is not currently known if these suits will ultimately be allowed to go forward.

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. Hoot Lake Plant is OTP's only facility that could be impacted by this rule. On January 25, 2007 the U.S. Court of Appeals for the Second Circuit remanded portions of the rule to the EPA. On December 3, 2010, the New York District Court approved a settlement agreement whereby the EPA is scheduled to issue revised 316(b) rules no later than July 27, 2012. OTP has completed an information collection program for the Hoot Lake Plant cooling water intake structure, but given the Court decisions OTP is uncertain of the impact on the facility at this time.

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 either been issued or are under renewal 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 wastes. 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 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 2010, approximately $43 million was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2010 gross electric property additions, including construction work in progress, were approximately $490 million and gross retirements were approximately $53 million. OTP estimates that during the five-year period 2011-2015 it will invest approximately $724 million for electric construction, which includes $264 million for OTP's share of a new Big Stone Plant AQCS and $188 million for new transmission projects including $130 million for CapX2020 transmission projects. The remainder of the 2011-2015 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant.

Franchises

At December 31, 2010 OTP had franchises to operate as an electric utility in all but three incorporated municipalities 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, 2010 OTP had 675 equivalent full-time employees and OTESCO had six equivalent full-time employees. A total of 409 OTP employees are represented by local unions of the International Brotherhood of Electrical Workers. One labor contract was renewed in the fall of 2008 and will expire in the fall of 2011. The other labor contract expired in the fourth quarter of 2010 and was renewed in February 2011. The renewed contract will expire in the fall of 2013. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good. Four employees of OTESCO are represented by UA (Plumbers & Steamfitters) Local 11. Their current contract will expire in spring 2011.

WIND ENERGY

General

Wind Energy consists of a steel fabrication company primarily involved in the production of wind towers, and a trucking company specializing in flatbed and heavy-haul services. The Company derived 18%, 19% and 22% of its consolidated operating revenues from the Wind Energy segment for each of the three years ended December 31, 2010, 2009 and 2008, respectively. Two customers account for over 70% of the 2010 revenue of the Wind Energy segment. Following is a brief description of these businesses:

DMI Industries, Inc. (DMI), with headquarters in Fargo, North Dakota, manufactures wind towers and other heavy metal fabricated products. DMI has manufacturing facilities in West Fargo, North Dakota; Tulsa, Oklahoma; and Ft. Erie, Ontario, Canada. DMI has a wholly owned subsidiary, DMI Canada, Inc., located in Ft. Erie, Ontario, Canada.

E. W. Wylie Corporation (Wylie), located in West Fargo, North Dakota, is a flatbed, heavy-haul and specialized contract and common carrier operating a fleet of tractors and trailers in 49 states and six Canadian provinces. Wylie has trucking terminals in West Fargo, North Dakota; Fort Worth, Texas; Denver, Colorado; and Albertville, Minnesota.

Competition

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

The trucking industry, in which Wylie participates, is highly competitive. Wylie competes primarily with other short- to medium-haul, flatbed truckload carriers, internal shipping conducted by existing and potential customers and, to a lesser extent, railroads. Wylie entered the transportation market in 2008 with specialized heavy-haul trucks and trailers capable of hauling wind towers. Competition for the freight transported by Wylie is based primarily on safety, service, efficiency and freight rates. There are other trucking companies that have greater financial resources, operate more equipment or carry a larger volume of freight than Wylie and these companies compete with Wylie for qualified drivers.

Raw Materials Supply and Diesel Fuel Prices

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

Backlog

The Wind Energy segment has backlog in place to support 2011 revenues of approximately $157 million compared with $176 million one year ago.

Legislation

The demand for wind towers manufactured by DMI depends in part on the existence of either renewable portfolio standards or a federal production tax credit for wind energy. Renewable portfolio standards exist in 29 states and seven additional states have renewable portfolio objectives. A federal production tax credit is in place through December 31, 2012.

Capital Expenditures

Capital expenditures in the Wind Energy segment typically include additional investments in new manufacturing equipment and new trucks or trailers or expenditures to replace aged manufacturing equipment, trucks and trailers. Capital expenditures may also be made for the purchase of land and buildings for plant expansion and for investments in management information systems. During 2010, capital expenditures of approximately $4 million were made in the Wind Energy segment. Total capital expenditures for the Wind Energy segment during the five-year period 2011-2015 are estimated to be approximately $54 million. These investments are primarily for developing new products and ventures and expanding existing product and service offerings at the Wind Energy companies. Operating leases are also used to finance the acquisition of trucks used by Wylie. Current operating lease commitments during the five-year period 2011-2015 are estimated to be $15 million.

Employees
At December 31, 2010 the Wind Energy segment had 838 full-time employees.

MANUFACTURING

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

The Company derived 16%, 16% and 17% of its consolidated operating revenues from the Manufacturing segment for each of the three years ended December 31, 2010, 2009 and 2008, 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, agriculture, lawn and garden, industrial equipment, health and fitness and enclosure industries. BTD's wholly owned subsidiary, Miller Welding and Iron Works, Inc., is located in Washington, Illinois and manufactures and fabricates parts for off-road equipment, mining machinery, oil fields and offshore oil rigs, wind industry components, broadcast antennae and farm equipment, and serves several major equipment manufacturers in the Peoria, Illinois area and nationwide, including Caterpillar, Komatsu and Gardner Denver.

ShoreMaster, Inc. (ShoreMaster), with headquarters in Fergus Falls, Minnesota, produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems that are marketed throughout the United States. ShoreMaster has four wholly owned subsidiaries, Galva Foam Marine Industries, Inc., Shoreline Industries, Inc., Aviva Sports, Inc., and ShoreMaster Costa Rica Limitada. ShoreMaster has manufacturing facilities located in Fergus Falls, Minnesota; Camdenton and Montreal, Missouri; and St. Augustine, Florida.

T. O. Plastics, Inc. (T.O. Plastics), located in Minneapolis and Clearwater, Minnesota, manufactures and sells thermoformed products for the horticulture industry throughout the United States. In addition, T.O. Plastics produces products such as clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts for other industries.

Competition
The various markets in which the Manufacturing segment entities compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources, excess capacity, labor advantages and larger marketing, research and development staffs and facilities than the Company's manufacturing entities.

The Company believes the principal competitive factors in its Manufacturing segment are product performance, quality, price, ease of use, technical innovation, cost effectiveness, customer service and breadth of product line. The Company's manufacturing entities intend to continue to compete on the basis of high-performance products, innovative technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

Raw Materials Supply
The companies in the Manufacturing segment use a variety of raw materials in the products they manufacture, including steel, aluminum, lumber, resin and concrete. Both pricing increases and availability of these raw materials are concerns of companies in the Manufacturing segment. The companies in the Manufacturing segment attempt to pass the increases in the costs of these raw materials on to their customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins in the Manufacturing segment.

Backlog
The Manufacturing segment has backlog in place to support 2011 revenues of approximately $86 million compared with $63 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 2010, capital expenditures of approximately $7 million were made in the Manufacturing segment. Total capital expenditures for the Manufacturing segment during the five-year period 2011-2015 are estimated to be approximately $47 million.

Employees
At December 31, 2010 the Manufacturing segment had 1,029 full-time employees.

CONSTRUCTION

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

The Company derived 12%, 10% and 12% of its consolidated operating revenues from the Construction segment for each of the years ended December 31, 2010, 2009 and 2008, respectively. Following is a brief description of the businesses included in this segment.

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

Aevenia, Inc. (Aevenia), located in Moorhead, Minnesota, is a holding company for subsidiaries that provide a full spectrum of electrical design and construction services for the industrial, commercial and municipal business markets, including government, institutional, utility communications, electric distribution and renewable energy generation.

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 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 $164 million for 2010 compared with $84 million one year ago.

Capital Expenditures
Capital expenditures in this segment typically include investments in additional construction equipment. During 2010, capital expenditures of approximately $5 million were made in the Construction segment. Capital expenditures during the five-year period 2011-2015 are estimated to be approximately $25 million for the Construction segment.

Employees
At December 31, 2010 there were 491 full-time employees in the Construction segment. Foley Company has 241 employees represented by various unions, including Carpenters and Millwrights, Sheet Metal Workers, Laborers, Operators, Operating Engineers, Pipe Fitters, Steamfitters, Plumbers and Teamsters. Moorhead Electric, Inc., a subsidiary of Aevenia, has 42 employees represented by local unions of the International Brotherhood of Electrical Workers and covered by a labor contract that expires on June 1, 2011. Foley Company has several labor contracts with various expiration dates in 2011 through 2013. Moorhead Electric, Inc. and Foley Company have not experienced any strike, work stoppage or strike vote, and consider their present relations with employees to be good.

PLASTICS

General
Plastics consists of businesses producing PVC pipe in the Upper Midwest and Southwest regions of the United States. The Company derived 9%, 8% and 9% of its consolidated operating revenues from the Plastics segment for each of the three years ended December 31, 2010, 2009 and 2008, 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. Over the last several years, there has been consolidation in PVC resin producers. There are a limited number of third party vendors that supply the PVC resin used by Northern Pipe and Vinyltech. Two vendors provided approximately 98% and 96% of total resin purchases in 2010 and 2009, 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 2010, capital expenditures of approximately $3 million were made in the Plastics segment. Total capital expenditures for the five-year period 2011-2015 are estimated to be approximately $9 million. This investment is primarily to replace existing equipment.

Employees
At December 31, 2010 the Plastics segment had 123 full-time employees.

HEALTH SERVICES

General
Health Services consists of DMS Health Technologies, which includes businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging equipment and technical staff to various medical institutions located throughout the United States.

The Company derived 9%, 11% and 9% of its consolidated operating revenues from the Health Services segment for each of the three years ended December 31, 2010, 2009 and 2008, respectively. The companies comprising DMS Health Technologies that deliver diagnostic imaging and healthcare solutions across the United States include:

DMS Health Technologies, Inc. (DMSHT), located in Fargo, North Dakota, sells and services diagnostic medical imaging equipment, cardiac and other patient monitoring equipment, defibrillators, EKGs and related medical supplies and accessories and provides ongoing service maintenance. DMSHT sells radiology equipment primarily manufactured by Philips Medical Systems (Philips), a large multi-national company based in the Netherlands. Philips manufactures fluoroscopic, radiographic and vascular equipment, along with ultrasound, computerized tomography (CT), magnetic resonance imaging (MRI), positron emission tomography (PET), PET/CT and cardiac catheterization labs. The business agreement with Philips expires on December 31, 2013. This agreement can be terminated on 180 days written notice by either party for any reason and can be terminated by Philips if certain compliance requirements are not met. DMSHT markets mainly to hospitals, clinics and mobile imaging service companies.

DMS Topline Medical, Inc. (Topline), DMSHT recently formed Topline, a subsidiary that sells and leases used and refurbished medical equipment to healthcare facilities. Topline sells both domestically and internationally to distributors and end users.

DMS Imaging, Inc. (DMSI), a subsidiary of DMSHT located in Fargo, North Dakota, provides diagnostic medical imaging equipment, including CT, MRI, PET and PET/CT and nuclear medicine, as well as technical staff, to health care facilities and other medical providers. Regional offices are located in Maple Grove, Minnesota; Los Angeles, California; and Sioux Falls, South Dakota. DMSI provides services through three different business units and one subsidiary:

- DMS Imaging—provides shared diagnostic medical imaging equipment and nonphysician personnel (primarily mobile) for MRI, CT, nuclear medicine, PET, PET/CT, ultrasound, mammography and bone density analysis.
- DMS Interim Solutions—offers interim and rental options for diagnostic imaging equipment.
- DMS MedSource Partners—develops long-term relationships with healthcare providers to offer dedicated in-house diagnostic imaging equipment.
- DMS Health Technologies—Canada, Inc., a subsidiary of DMSI, is located in Fargo, North Dakota. It provides limited interim and rental options for diagnostic equipment to Canadian healthcare entities.

Combined, DMS Health Technologies covers the three basics of the medical imaging industry: (1) ownership and operation of the imaging equipment for healthcare providers; (2) sale, lease and/or maintenance of medical imaging equipment and related supplies; and (3) technical and administrative support of medical imaging services.

Regulation

The healthcare industry is subject to extensive federal and state regulations relating to licensure, conduct of operation, ownership of facilities, payment of services and expansion or addition of facilities and services.

The federal Anti-Kickback Statute prohibits persons from knowingly and willfully soliciting, receiving, offering or providing remuneration, directly or indirectly, to induce the referral of an individual or the furnishing or arranging for a good or service for which payment may be made under a federal healthcare program such as Medicare or Medicaid. Several states have similar statutes. The term "remuneration" has been broadly interpreted to include anything of value, including, for example, gifts, discounts, credit arrangements, payments of cash, waiver of payments and ownership interests. Penalties for violating the Anti-Kickback Statute can include both criminal and civil sanctions as well as possible exclusion from participating in federal healthcare programs.

The Ethics and Patient Referral Act of 1989 (Stark Law) prohibits a physician from making referrals for certain designated health services payable under Medicare, including services provided by the Health Services companies, to an entity with which the physician has a financial relationship, unless certain exceptions apply. The Stark Law also prohibits an entity from billing for designated health services pursuant to a prohibited referral. A person who engages in a scheme to violate the Stark Law or a person who presents a claim to Medicare in violation of the Stark Law may be subject to civil fines and possible exclusion from participation in federal healthcare programs. Several states have similar statutes, the violation of which can result in civil fines and possible exclusion from state healthcare programs. From time to time, the Center for Medicare and Medicaid Services (CMS) considers additional modifications to the Stark Law that may further limit the ability of physicians to provide certain imaging services. Changes to Stark Law effective October 1, 2009 expand Stark Law coverage to persons and entities that "perform" designated health services. CMS has not defined what it means to perform designated health services.

The Patient Protection and Affordable Care Act and The Health Care and Education Reconciliation Act of 2010 (the Affordable Care Act), were signed into law by President Obama in March 2010, and will result in significant reforms to the U.S. healthcare system and the structure of the healthcare provider delivery system. The Affordable Care Act will create new payment methodologies and mechanisms under the Medicare and Medicaid programs to link payment with quality and cost-effective service delivery. The overall goal of the Affordable Care Act is to create a more integrated, coordinated, and more efficient healthcare delivery system. The full impact of the Affordable Care Act is uncertain, and will depend on future regulations and guidance to be promulgated by CMS. Any new reimbursement methodologies and mechanisms adopted by Medicare, Medicaid, or other commercial third party payors as a direct or indirect result of the Affordable Care Act could have an impact on the demand for diagnostic tests.

In addition, Section 3135 of the Affordable Care Act will result in a reduction in Medicare payment for advanced imaging services, such as CT and MRI tests. Under that provision, beginning January 2011 Medicare will presume a higher rate of utilization of advanced diagnostic imaging equipment, resulting in lower Medicare reimbursement for each test. This reimbursement reduction, as well as any other reimbursement changes resulting from the Affordable Care Act, could have an impact on the demand for imaging services.

Many vested organizations, including healthcare advocacy groups, continue to analyze the new law to determine and communicate its impacts on the healthcare industry. To this point, the impact on the imaging sector is viewed in broad terms; that is, coverage of millions of new lives under the Affordable Care Act will likely increase volume and demand for imaging services. While some revenue streams may be reduced, it is anticipated that hospitals will gain additional revenues through an expansion of insurance coverage while Independent Diagnostic Testing Facilities (IDTFs) are scheduled for Medicare reimbursement decreases based upon a change in the Medicare formula related to expected utilization rates.

The Affordable Care Act also provides the federal government with increased authority and tools to combat health care fraud and abuse, including additional subpoena powers, the ability to provide additional screening for new providers in the Medicare and Medicaid program, and the authority to withhold Medicare payment to a provider while an investigation is pending, among others.

On May 20, 2009 President Obama signed the Fraud Enforcement and Recovery Act of 2009, which substantially amends the federal False Claims Act. These amendments significantly expand the scope of liability for individuals and entities that receive government funds, including health care providers and suppliers receiving federal funds through Medicare or Medicaid. As amended, the False Claims Act imposes liability on those who knowingly make false or fraudulent claims for federal funds or property, whether or not the claim is presented to a government official or employee. A suit under the False Claims Act can be brought directly by the United States Department of Justice, or can be brought by a "whistleblower." A whistleblower brings suit on behalf of themselves and the United States, and the whistleblower is awarded a percentage of any recovery. Conduct that has given rise to False Claims Act liability includes but is not limited to current and past failures to comply with technical Medicare and Medicaid billing requirements, failure to comply with certain Medicare documentation requirements, and failure to comply with Medicare physician supervision requirements. Violations of the Stark Law and Anti-Kickback Statute have also served as the basis of False Claims Act liability. Many states have adopted or are seeking to adopt state false claims act laws modeled on the federal statute.

The Health Insurance Portability and Accountability Act of 1996 (HIPAA) created federal crimes related to healthcare fraud and to making false statements related to healthcare matters. HIPAA prohibits knowingly and willfully executing a scheme to defraud any healthcare benefit program including a program involving private payors. Further, HIPAA prohibits knowingly and willfully falsifying, concealing or covering up a material fact or making any materially false statement in connection with the delivery of or payment for healthcare benefits or services. HIPAA also provides rules to protect the privacy and security of certain patient information.

President Obama signed into law on February 17, 2009 the Health Information Technology for Economic and Clinical Health Act that among other things, amends and expands HIPAA privacy and security rules, and provides for enhanced enforcement of HIPAA privacy violations by covered entities and contractors Entities that experience certain privacy or data breaches are subject to significant fines.

In some states a certificate of need or similar regulatory approval is required prior to the acquisition of high-cost capital items or services, including diagnostic imaging systems or the provision of diagnostic imaging services by companies or its customers. Certificate of need laws were enacted to contain rising healthcare costs by preventing unnecessary duplication of health resources.

Over the last two years CMS has issued rule changes increasing the oversight of IDTFs, which are imaging facilities that enroll in the Medicare Program as participating Medicare suppliers and receive reimbursement directly from the Medicare program for services provided to Medicare beneficiaries. These regulations delineate certain stringent performance standards for IDTFs including standards for physical facilities, patient privacy, technician qualifications, insurance, equipment inspections, reporting changes to CMS, physician supervision, and the manner in which IDTFs are defined and enrolled in Medicare. These standards also include a provision prohibiting certain staff or space sharing arrangements. DMSI has taken steps to eliminate mobile IDTFs from its operating portfolio in 2010, and has thereby significantly reduced Medicare compliance risk to the organization.

Rules published as part of the 2008 Medicare Physician Fee Schedule expanded the scope of the federal anti-markup rule for diagnostic tests, a federal law which delineates instances wher physicians and other suppliers are prohibited from marking-up to Medicare the price of diagnostic tests when the physician performing or supervising the test does not share a practice with the billing physician or other supplier.

In 2008, CMS also finalized regulations that require mobile diagnostic entities under certain circumstances to enroll in the Medicare program for diagnostic tests that they perform and to bill Medicare directly these tests. Medicare has published guidance indicating that entities that lease or contract with a Medicare enrolled supplier or provider to provide equipment and/or nonphysician personnel need not enroll in Medicare and bill directly for tests performed. Both the changes to the Medicare anti-markup rule and the mobile diagnostic testing rules are subject to interpretation by Medicare and local Medicare carriers, and could require us to make operational changes. Furthermore, if we are found not to be in compliance with these rules, or if Medicare reimbursement available to certain customers is impaired by these rules, our business could be adversely affected.

Additional federal and state regulations that the Health Services companies are subject to include state laws that prohibit the practice of medicine by non-physicians and prohibit fee-splitting arrangements involving physicians; Federal Food and Drug Administration requirements; state licensing and certification requirements; and federal and state laws governing diagnostic imaging and therapeutic equipment. Courts and regulatory authorities have not fully interpreted a significant number of the current laws and regulations.

The Medicare Improvements for Patients and Providers Act of 2008 (MIPPA) requires suppliers of technical components of certain advanced imaging services to obtain CMS-approved accreditation by January 1, 2012. The MIPPA, which excludes hospitals from the accreditation requirements, may impact some of DMSI's customers.

The Health Services companies continue to monitor developments in healthcare law. The Health Services companies believe their operations comply with these laws and they are prepared to modify their operations from time to time as the legal and regulatory environment changes. However, there can be no assurances that the Health Services companies will always be able to modify their operations to address changes in the legal and regulatory environment without any adverse effect to their financial performance. The consequences of failing to comply with applicable laws can be severe, including criminal penalties. In many instances violations of applicable law can result in substantial fines and damages. Moreover, in some cases violations of applicable law can result in exclusion in participation in federal and state healthcare programs. If any of the Health Services companies were excluded from participation in federal or state healthcare programs, our customers who participate in those programs could not do business with us.

Reimbursement

Health Services customers are primarily healthcare entities and providers that receive the majority of their payments from Medicare, Medicaid, managed care plans and other third-party payors. Payments by third-party payors to such healthcare entities and providers depend, in part, upon their patients' health insurance benefits and policies. New Medicare regulations reduced 2006 Medicare reimbursement for certain imaging services performed on contiguous body parts during the same day. The Affordable Care Act reduced the Medicare reimbursement amount for these same day imaging services performed on contiguous body parts even further. In addition, the Deficit Reduction Act of 2005 (DRA) limited reimbursement for imaging services provided in physician offices and in free-standing imaging centers to the reimbursement amount for that same service when provided in a hospital outpatient department. This DRA provision impacted a small number of imaging services provided by the Health Services companies. Federal and state legislatures may seek additional cuts in Medicare and Medicaid programs that could impact the value of the services provided by the Health Services segment. In addition, commercial third party payors may in the future choose to adopt any of the reimbursement cuts implemented under the Medicare or Medicaid programs.

Competition

The market for selling, servicing and operating diagnostic imaging services, patient monitoring equipment and imaging systems is highly competitive. In addition to direct competition from other providers of items and services similar to those offered by the Health Services companies, the companies within Health Services compete with free-standing imaging centers and health care providers that have their own diagnostic imaging systems, as well as with equipment manufacturers that sell imaging equipment directly to healthcare providers for permanent installation. Some of the direct competitors, which provide contract MRI and PET/CT services, have access to greater financial resources than the Health Services companies. In addition, some Health Services customers are capable of providing the same services to their patients directly, subject only to their decision to acquire a high-cost diagnostic imaging system, assume the financial and technology risk, and employ the necessary technologists, rather than obtain equipment and services from the Health Services companies. The Health Services companies may also experience greater competition in states that currently have certificate of need laws if such laws were repealed, thereby reducing barriers to entry and competition in that state. The Health Services companies compete against other similar providers on the basis of quality of services, quality and magnetic field strength of imaging systems, relationships with health care providers, knowledge and service quality of technologists, price, availability and reliability.

Environmental, Health or Safety Laws

PET, PET/CT and nuclear medicine services require the use of radioactive material. While this material has a short life and quickly breaks down into inert, or non-radioactive substances, using such materials presents the risk of accidental environmental contamination and physical injury. Federal, state and local regulations govern the storage, use and disposal of radioactive material and waste products. The Company believes that its safety procedures for storing, handling and disposing of these hazardous materials comply with the standards prescribed by law and regulation; however the risk of accidental contamination or injury from those hazardous materials cannot be completely eliminated. The companies in the Health Services segment have not had any material expenses related to environmental, health or safety laws or regulations.

Capital Expenditures

Capital expenditures in this segment principally relate to the acquisition of diagnostic imaging equipment used in the imaging business. During 2010, capital expenditures of approximately $22 million were made in the Health Services segment. Total capital expenditures during the five-year period 2011-2015 are estimated to be approximately $79 million. This investment is primarily to replace existing equipment, both owned and coming off lease under operating leases. Operating leases had previously been the primary means for financing the imaging equipment used to operate the business. By minimizing operating leases and financing more capital purchases, operating costs are better aligned to approximate the life of the imaging equipment and result in improved cash flow from operations. To a much lesser degree than in past years, operating leases are also used to finance the acquisition of medical equipment used by Health Services companies. Current operating lease commitments during the five-year period 2011-2015 are estimated to be $12 million in 2011, $5 million in 2012, $1 million in 2013 and less than $20,000 in 2014 and 2015 combined.

Employees

At December 31, 2010 the Health Services segment had 274 full-time employees.

FOOD INGREDIENT PROCESSING

General

Food ingredient processing consists of Idaho Pacific Holdings, Inc. (IPH), headquartered in Ririe, Idaho, manufactures and supplies dehydrated potato products to food manufacturers in the snack food, bakery and foodservice industries. IPH has three processing facilities located in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. Together these three facilities have the capacity to process approximately 114 million pounds of dehydrated potato products annually.

The Company derived 7%, 8% and 5% of its consolidated operating revenues from the Food Ingredient Processing segment for each of the years ended December 31, 2010, 2009 and 2008, respectively.

Customers

IPH sells to customers in the United States and internationally. Products are sold through company sales persons, agents and broker sales representatives. Customers include end users in the food manufacturing industry and distributors to the food manufacturing industry and foodservice industry, both domestically and internationally.

Competition

The market for processed, dehydrated potato flakes, flour and granules is highly competitive. The ability to compete depends on superior product quality, competitive product pricing and strong customer relationships. IPH competes with numerous manufacturers and dehydrators of varying sizes in the United States and overseas, including companies with greater financial resources.

Potato Supply

The principal raw material used by IPH is washed process-grade potatoes from fresh packing operations and growers. These potatoes are unsuitable for use in other markets due to imperfections. They do not meet United States Department of Agriculture's general requirements and expectations for size, shape or quality. While IPH has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers and other factors. A loss of raw materials or the necessity of paying much higher prices for raw materials could adversely affect the financial performance of IPH.

Regulation

IPH is regulated by the United States Department of Agriculture and the Federal Food and Drug Administration and other federal, state, local and foreign governmental agencies relating to the quality of products, sanitation, food safety and environmental compliance. IPH adheres to strict manufacturing practices that dictate sanitary conditions conducive to a high quality food product. All facilities use wastewater systems that are regulated by government environmental agencies in their respective locations and are subject to permitting by these agencies. IPH believes that it complies with applicable laws and regulations in all material respects, and that continued compliance with such laws and regulations will not have a material effect on its capital expenditures, earnings or competitive position.

Capital Expenditures

Capital expenditures in the Food Ingredient Processing segment typically include additional investments in new dehydration equipment or expenditures to replace worn-out equipment and improve efficiency. Capital expenditures may also be made for the purchase of land and buildings for plant capacity expansion and for investments in management information or waste-water treatment systems. During 2010, capital expenditures of $1 million were made in the Food Ingredient Processing segment. Total capital expenditures for the Food Ingredient Processing segment to support growth and margin improvement during the five-year period 2011-2015 are estimated to be approximately $17 million.

Employees

At December 31, 2010 the Food Ingredient Processing segment had 407 full-time employees.

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 $20.0 million discretionary contribution to our defined benefit pension plan in 2010. We could be required to contribute additional capital to the pension plan in future years if the market value of pension plan assets significantly declines in the future, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

Any significant impairment of our goodwill would cause a decrease in our asset values and a reduction in our net operating performance.
We had approximately $94.1 million of goodwill recorded on our consolidated balance sheet as of December 31, 2010. We have recorded goodwill for businesses in each of our business segments except Electric. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net operating performance. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying amount of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge.

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

The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and debt covenants and pay dividends to our shareholders could have an adverse effect on the Company.
Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the actual and projected earnings, cash flows, capital requirements and general financial position of our subsidiary companies, as well as regulatory factors, financial covenants, general business conditions and other matters. Under our $200 million revolving credit agreement we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00. While this restriction is not expected to affect our ability to pay dividends at the current level in the foreseeable future, there is no assurance that adverse financial results would not reduce or eliminate our ability to pay dividends. Our dividend payout ratio has exceeded 100% of our earnings in each of the last three 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 diversify through acquisitions may not be successful, which could result in poor financial performance.
As part of our business strategy, we intend to acquire new businesses. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. If we are unable to make acquisitions, we may be unable to realize the growth we anticipate. 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 of an acquisition, we could face reductions in net income in future periods.

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

We enter into production and construction contracts, including contracts for new product designs, which could expose us to unforeseen costs and costs not within our control, which may not be recoverable and could adversely affect our results of operations and financial condition.
DMI, ShoreMaster and our construction companies frequently provide products and services pursuant to fixed-price contracts. Revenues recognized on jobs in progress under fixed-price contracts were $491 million at December 31, 2010 and $460 million at December 31, 2009. Under those contracts, we agree to perform the contract for a fixed price and, as a result, can improve our expected profit by superior contract performance, productivity, worker safety and other factors resulting in cost savings. However, we could incur cost overruns above the approved contract price, which may not be recoverable.

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

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

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

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

ELECTRIC

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

In September 2009, OTP announced its withdrawal as a participating utility and the lead developer for the planned construction of a second electric generating unit at its Big Stone Plant site. As of December 31, 2010 OTP had $7.9 million in incurred costs related to the project that have not been approved for recovery and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve its rates. If OTP is denied recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed to be unrecoverable. Additionally, if OTP is unable to find alternatives to the project to meet generation needs, it may be forced to purchase power in order to meet customer needs. There is no guarantee that in such a case OTP would be able to obtain sufficient supplies of power at reasonable costs. If OTP is forced to pay higher than normal prices for power, the increase in costs could reduce our earnings if OTP is not able to recover the increased costs from its electric customers through the fuel clause adjustment.

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.

OTP could be required to absorb a disproportionate share of costs for investments in transmission infrastructure required to provide independent power producers access to the transmission grid. 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 CO_2 emissions, could affect our operating costs and the costs of supplying electricity to our customers.
Existing or new laws or regulations passed or issued by federal or state authorities addressing climate change or reductions of greenhouse gas emissions, such as mandated levels of renewable generation, mandatory reductions in CO_2 emission levels, taxes on CO_2 emissions or cap and trade regimes, could require us to incur significant new costs, which could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where OTP provides service or through increased market prices for electricity. Debate continues in Congress on the direction and scope of U.S. policy on climate change and regulation of GHGs. Congress has considered but has not adopted GHG legislation which would require a reduction in GHG emissions and there is no legislation under active consideration at this time. The likelihood of any federal mandatory CO_2 emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, are uncertain. The EPA has begun to regulate GHG gas emissions under its "endangerment" finding. The EPA has adopted its first GHG emission control rules for motor vehicles and new source review of stationary sources of GHGs, which became applicable to motor vehicles and stationary sources, respectively, on January 2, 2011. The EPA plans to adopt standards of performance for emissions from power plants and refineries by mid-2012. Specific requirements of regulation under the CAA's various programs, and thus their impact on OTP, are uncertain at this time.

WIND ENERGY

Competition from foreign and domestic manufacturers, cost management in a fixed price contract project environment, fluctuations in foreign currency exchange rates and general economic conditions could affect the revenues and earnings of our Wind Energy segment.
Our Wind Energy segment is subject to risks associated with competition from foreign and domestic manufacturers, some of whom have greater distribution capabilities, greater capital resources and other capabilities that may place downward pressure on margins and profitability. Our wind tower manufacturer operates in a fixed price project environment where balancing workload to costs can create variation in margins that may not be recoverable from customers. Diesel fuel is a major expense for our trucking company. Diesel fuel prices are subject to volatility due to fluctuations in oil prices and domestic and world-wide production levels and capacity. If the companies in our Wind Energy segment are not able to recover cost increases from their customers, it could have a negative effect on profit margins and income from our Wind Energy segment.

Fluctuations in foreign currency exchange rates could have a negative impact on the net income and competitive position of our wind tower manufacturing operations in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

The U.S. wind industry is reliant on tax and other economic incentives and political and governmental policies. A significant change in these incentives and policies could negatively impact our results of operations and growth.
Our wind tower manufacturing business is focused on supplying towers to wind turbine manufacturers and owners and operators of wind energy generation facilities. The wind industry is dependent on federal tax incentives and state renewable portfolio standards and may not be economically viable absent such incentives.

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

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

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

MANUFACTURING

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

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

CONSTRUCTION

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

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 98% of our total purchases of PVC resin in 2010 and approximately 96% of our total purchases of PVC resin in 2009. 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.

HEALTH SERVICES

Changes in the rates or methods of third-party reimbursements for our diagnostic imaging services could result in reduced demand for those services or create downward pricing pressure, which would decrease our revenues and earnings.
Customers who use our diagnostic imaging services generally rely on reimbursement from third-party payors. Adverse changes in the rates or methods of third-party reimbursements, related to the Affordable Care Act or otherwise, could reduce the number of procedures for which we or our customers can obtain reimbursement or the amounts reimbursed to us or our customers.

The Affordable Care Act was signed into law by President Obama in March 2010, and will result in significant reforms to the U.S. healthcare system and the structure of the healthcare provider delivery system. The Affordable Care Act will create new payment methodologies and mechanisms under the Medicare and Medicaid programs to link payment with quality and cost-effective service delivery. The overall goal of the Affordable Care Act is to create a more integrated, coordinated, and more efficient healthcare delivery system. The full impact of the Affordable Care Act is uncertain, and will depend on future regulations and guidance to be promulgated by CMS. Any new reimbursement methodologies and mechanisms adopted by Medicare, Medicaid, or other commercial third party payors as a direct or indirect result of the Affordable Care Act could have an impact on the demand for our diagnostic tests.

In addition, Section 3135 of the Affordable Care Act will result in a reduction in Medicare payment for advanced imaging services, such as CT and MRI tests. Under that provision, beginning January 2011 Medicare will presume a higher rate of utilization of advanced diagnostic imaging equipment, resulting in lower Medicare reimbursement for each test. This reimbursement reduction, as well as any other reimbursement changes resulting from the Affordable Care Act, could have an impact on the demand for our imaging services.

The Affordable Care Act also provides the federal government with increased authority and tools to combat health care fraud and abuse, including additional subpoena powers, the ability to provide additional screening for new providers in the Medicare and Medicaid program, and the authority to withhold Medicare payment to a provider while an investigation is pending, among others. While we are unable at this time to predict what additional reforms will be implemented, or the effect that any future legislation or regulation will have on us, it is possible that our health services business may be adversely affected by such reforms, legislation or regulation.

Our health services businesses may be unable to continue to maintain agreements with Philips from which we derive significant revenues from the sale and service of Philips diagnostic imaging equipment.
Our health services business agreement with Philips expires on December 31, 2013. This agreement can be terminated on 180 days written notice by either party for any reason. It also includes other compliance requirements. If this agreement is terminated under the existing termination provisions or we are not able to comply with the agreement, the financial results of our health services operations would be adversely affected.

Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require our health services operations to incur significant costs to upgrade its equipment.
Although we believe substantially all of our diagnostic imaging systems can be upgraded to maintain their state-of-the-art character, the development of new technologies or refinements of existing technologies might make our existing systems technologically or economically obsolete, or cause a reduction in the value of, or reduce the need for, our systems.

Actions by regulators of our health services operations could result in monetary penalties or restrictions in our health services operations.
Our health services operations are subject to federal and state regulations relating to licensure, conduct of operations, ownership of facilities and relationships with customers. Our failure to comply with these regulations or our inability to obtain and maintain necessary regulatory approvals, may result in adverse actions by regulators with respect to our health services operations, which may include civil and criminal penalties, damages, fines, injunctions, operating restrictions or suspension of operations. Any such action could adversely affect our financial results. Courts and regulatory authorities have not fully interpreted a significant number of these laws and regulations, and this uncertainty in interpretation increases the risk that we may be found to be in violation. Any action brought against us for violation of these laws or regulations, even if successfully defended, may result in significant legal expenses and divert management's attention from the operation of our businesses.

FOOD INGREDIENT PROCESSING

Our company that processes dehydrated potato flakes, flour and granules, IPH, competes in a highly competitive market and is dependent on adequate sources of potatoes for processing.
The market for processed, dehydrated potato flakes, flour and granules is highly competitive. The profitability and success of our potato processing company is dependent on superior product quality, competitive product pricing, strong customer relationships, raw material costs, fuel prices and availability and customer demand for finished goods. In most product categories, our company competes with numerous manufacturers of varying sizes in the United States.

The principal raw material used by IPH is washed process-grade potatoes from growers and potato fresh packing operations. These potatoes are unsuitable for use in other markets due to imperfections. They are not subject to the United States Department of Agriculture's general requirements and expectations for size, shape or color. While our food ingredient processing company has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key suppliers, loss of potato production acres to other crops, and other factors. A loss or shortage of raw materials or the necessity of paying much higher prices for raw materials or fuel could adversely affect the financial performance of this company. Fluctuations in foreign currency exchange rates could have a negative impact on our potato processing company's net income and competitive position because approximately 18% of IPH sales in 2010 and approximately 16% of IPH sales in 2009 were outside the United States and the Canadian plant pays its operating expenses in Canadian dollars.

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 with a combined nameplate rating of 128,500 kW. 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 (66,000 kW nameplate rating) and modified in 1988 to provide cycling capability, allowing this unit to be more efficiently brought online from a standby mode.

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, 2010 OTP's transmission facilities, which are interconnected with lines of other public utilities, consisted of 48 miles of 345 kV lines; 417 miles of 230 kV lines; 862 miles of 115 kV lines; and 3,976 miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of the 48 miles of the 345 kV line, with Minnkota Power Cooperative retaining title to the original 230 kV construction.

In addition to the properties mentioned above, the Company owns and has investments in offices and service buildings. The Company's subsidiaries own: construction equipment and tools, medical imaging equipment, a fleet of flatbed trucks and trailers and facilities and equipment used to manufacture PVC pipe, wind towers and other heavy metal fabricated products, thermoformed products, and commercial and waterfront equipment; produce dehydrated potato products; and perform metal 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

Sierra Club Complaint

On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act (CAA) and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the CAA and the South Dakota SIP. The Sierra Club alleged the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the CAA and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the U.S. District Court for the District of South Dakota (Northern Division) issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a Motion for Reconsideration of the Amended Memorandum and Order. The District Court denied the motion on July 22, 2009. On July 30, 2009 the Sierra Club appealed the District Court's decision to the U. S. Court of Appeals for the 8th Circuit. On August 12, 2010 the U.S. Court of Appeals for the 8th Circuit affirmed the District Court decision dismissing the Sierra Club's suit against Big Stone Plant. The District Court's decision is now final because the Sierra Club did not file a petition for rehearing with the Court of Appeals and did not petition for writ of certiorari with the U.S. Supreme Court by the respective deadlines.

Other

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 25, 2011)

Set forth below is a summary of the principal occupations and business experience during the past five years of the executive officers as defined by rules of the Securities and Exchange Commission. Each of the executive officers has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly owned subsidiary, Otter Tail Power Company, except for Ms. Kommer, who was attending law school prior to 2007 and was employed by the Company as an in-house attorney from 2007 until she was named Vice President of Human Resources in 2009.

Name and Age	Dates Elected to Office	Present Position and Business Experience	
John D. Erickson (52)	4/8/02	Present:	President and Chief Executive Officer
George A. Koeck (58)	4/10/00	Present:	Corporate Secretary and General Counsel
Kevin G. Moug (51)	4/9/01	Present:	Chief Financial Officer
Michelle L. Kommer (38)	4/12/10	Present:	Senior Vice President of Human Resources
Charles S. MacFarlane (46)	5/1/03	Present:	President, Otter Tail Power Company

With the exception of Charles S. MacFarlane, the term of office for each of the executive officers is one year and any executive officer elected may be removed by the vote of the Board of Directors at any time during the term. Mr. MacFarlane is not appointed by the Board of Directors. Mr. MacFarlane is a son of John MacFarlane, who is the Chairman of the Board of Directors. There are no other family relationships between any of the executive officers or directors.

ITEM 4. [REMOVED AND RESERVED]

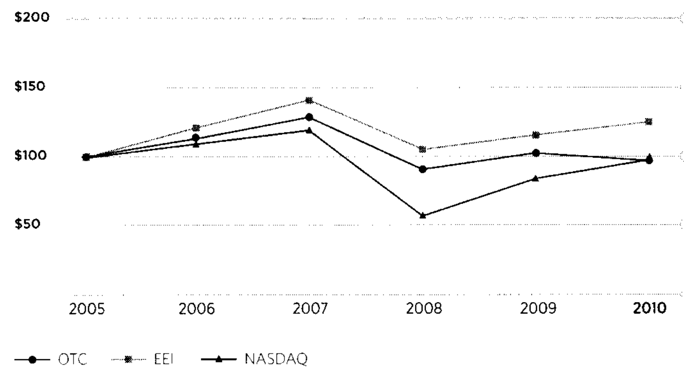
PART II

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 34 of this Annual Report on Form 10-K under the heading "Selected Financial Data," on Page 77 under the heading "Retained Earnings Restriction" and on Page 86 under the heading "Quarterly Information." The Company did not repurchase any equity securities during the three months ended December 31, 2010.

PERFORMANCE GRAPH
COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

This graph compares the cumulative total shareholder return on the Company's common shares for the last five fiscal years with the cumulative return of The NASDAQ Stock Market Index and the Edison Electric Institute Index (EEI) over the same period (assuming the investment of $100 in each vehicle on December 30, 2005, and reinvestment of all dividends).



	2005	2006	2007	2008	2009	2010
OTC	$ 100.00	$ 111.82	$ 128.55	$ 90.08	$ 101.25	$ 97.36
EEI	$ 100.00	$ 120.76	$ 140.75	$ 104.29	$ 115.46	$ 123.58
NASDAQ	$ 100.00	$ 109.84	$ 119.14	$ 57.41	$ 82.53	$ 97.95

ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except number of shareholders and per-share data)	**2010**	2009	2008	2007	2006
Revenues					
Electric	$ 340,313	$ 314,666	$ 340,075	$ 323,591	$ 306,231
Wind Energy	197,746	192,923	290,832	219,276	171,274
Manufacturing	178,690	164,186	222,482	198,061	175,799
Construction	134,222	103,831	157,053	150,721	110,488
Plastics	96,945	80,208	116,452	149,012	163,135
Health Services	100,301	110,006	122,520	130,670	135,051
Food Ingredient Processing	77,412	79,098	65,367	70,440	45,084
Corporate Revenues and Intersegment Eliminations	(6,545)	(5,406)	(3,584)	(2,884)	(2,108)
Total Operating Revenues	$1,119,084	$1,039,512	$1,311,197	$1,238,887	$1,104,954
Net Income (Loss) from Continuing Operations	$ (1,344)	$ 26,031	$ 35,125	$ 53,961	$ 50,750
Net Income from Discontinued Operations	—	—	—	—	362
Net Income (Loss)	$ (1,344)	$ 26,031	$ 35,125	$ 53,961	$ 51,112
Operating Cash Flow from Continuing Operations	$ 105,017	$ 162,750	$ 111,321	$ 84,812	$ 79,207
Operating Cash Flow—Continuing and Discontinued Operations	105,017	162,750	111,321	84,812	80,246
Capital Expenditures—Continuing Operations	85,589	177,125	265,888	161,985	69,448
Total Assets	1,770,555	1,745,678	1,692,587	1,454,754	1,258,650
Long-Term Debt	435,446	436,170	339,726	342,694	255,436
Basic Earnings (Loss) Per Share—Continuing Operations (1)	(0.06)	0.71	1.09	1.79	1.70
Basic Earnings (Loss) Per Share—Total (1)	(0.06)	0.71	1.09	1.79	1.71
Diluted Earnings (Loss) Per Share—Continuing Operations (1)	(0.06)	0.71	1.09	1.78	1.69
Diluted Earnings (Loss) Per Share—Total (1)	(0.06)	0.71	1.09	1.78	1.70
Return on Average Common Equity	(0.3)%	3.8%	6.0%	10.5%	10.6%
Dividends Per Common Share	1.19	1.19	1.19	1.17	1.15
Dividend Payout Ratio	—	168%	109%	66%	68%
Common Shares Outstanding—Year End	36,003	35,812	35,385	29,850	29,522
Number of Common Shareholders (2)	14,848	14,923	14,627	14,509	14,692

Notes: (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 seven segments: Electric, Wind Energy, Manufacturing, Construction, Plastics, Health Services and Food Ingredient Processing. 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, along with our nonelectric operating companies. Reliable utility performance along with rate base investment opportunities over the next four to seven years will provide a strong base of revenues, earnings and cash flows. We also look to our nonelectric operating companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. We expect much of our growth in our nonelectric businesses in the next few years will come from utilizing expanded plant capacity from capital investments made in previous years. We believe that owning well-run, profitable companies across different industries will bring more growth opportunities and more balance to our results. In doing this, we also avoid concentrating business risk within a single industry. All of our operating companies operate under a decentralized business model with disciplined corporate oversight.

We assess the performance of our operating companies over time, using the following criteria:

- ability to provide returns on invested capital that exceed our weighted average cost of capital over the long term; and
- assessment of an operating company's business and potential for future earnings growth.

We are a committed long-term owner and therefore we do not acquire companies in pursuit of short-term gains. However, we may divest operating companies that no longer fit into our strategy and risk profile over the long term.

Major growth strategies and initiatives in our company's future include:

- Planned capital budget expenditures of up to $956 million for the years 2011 through 2015 of which $724 million is for capital projects at Otter Tail Power Company (OTP), including $264 million for OTP's share of a new air quality control system at Big Stone Plant and $188 million for anticipated expansion of transmission capacity including $130 million for CapX2020 transmission projects. See "Capital Requirements" section for further discussion.
- Utilization of expanded plant capacity from capital investments made in our nonelectric businesses.
- The continued investigation and evaluation of organic growth and strategic acquisition opportunities as well as divestiture opportunities which will allow us to raise internal capital to support our future capital expenditure plans and adjust our overall risk profile.

In 2010:

- Our net cash from operations was $105.0 million.
- Our Electric segment net income increased 2.6% to $34.6 million.
- Our Plastics segment net income increased $2.6 million.
- Our Health Services segment net income increased $2.3 million.
- Our Food Ingredient Processing segment net income increased 8.0% to a record $8.0 million.
- Our Wind Energy segment lost $21.2 million. DMI incurred additional costs related to fulfilling the fabrication specifications for a customer's new wind tower design. These efforts resulted in lower productivity and higher costs as they involved a combination of adding staff and reallocating existing resources within DMI to meet the customer's delivery requirements. Actions are being taken to improve production efficiency and to further the critical relationships that DMI continues to build with key wind turbine manufacturers.
- Our Manufacturing segment lost $14.8 million as a result of a $15.6 million net-of-tax asset impairment charge at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment manufacturer.

Segment components of the corporation's 2010 earnings (loss) per share on a GAAP basis and excluding the effects of certain nonrecurring or noncash charges are presented in the table below:

	Electric	Wind Energy	Mfg.	Const.	Plastics	Health Services	Food	Corp.	Total EPS
GAAP Basis	$0.97	($0.59)	($0.41)	($0.02)	$0.07	$0.00	$0.22	($0.30)	($0.06)
Nonrecurring or Noncash Items:									
Health Care Reform Tax Impact	0.05								0.05
Asset Impairment Charge			0.44						0.44
Canadian Operating Loss Carryforward Deferred Tax Valuation Allowance		0.15							0.15
Impact on Deferred Taxes of Reduction in Canadian Tax Rate		0.03							0.03
Other		0.01							0.01
Adjusted Basis	$1.02	($0.40)	$0.03	($0.02)	$0.07	$0.00	$0.22	($0.30)	$0.62

Comparison of GAAP to Non-GAAP Financial Measures—Non-GAAP financial measurements in this report are provided to assist in understanding the impact of certain nonrecurring, noncash charges. The corporation believes that adjusting for certain one-time costs will assist investors in making an evaluation of our performance. This information should not be construed as an alternative to the reported results, which have been determined in accordance with accounting principles generally accepted in the United States of America.

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

(in thousands)	2010	2009
Operating Revenues:		
Electric	$ 340,078	$ 314,467
Nonelectric	779,006	725,045
Total Operating Revenues	$ 1,119,084	$ 1,039,512
Net Income (Loss):		
Electric	$ 34,557	$ 33,678
Nonelectric	(25,946)	1,737
Corporate	(9,955)	(9,384)
Total Net Income (Loss)	$ (1,344)	$ 26,031

The 7.7% increase in consolidated revenues in 2010 compared with 2009 reflects increased revenue from our Electric, Wind Energy, Manufacturing, Construction and Plastics segments. Electric segment revenues increased by $25.6 million as result of: (1) a $19.0 million increase in retail revenues mainly due to increased resource recovery and transmission rider revenues, higher kilowatt-hour (kwh) sales to retail commercial customers, and rate increases in Minnesota and South Dakota, and (2) a $7.5 million increase in wholesale revenues from company-owned generation, offset by (3) a $0.8 million decrease in other electric revenues. Revenues from our Construction segment increased $30.4 million as improving economic conditions in this segment have resulted in an increase in volume of jobs in progress. Revenues increased by $16.7 million in our Plastics segment as a result of higher pipe prices combined with a 4.1% increase in pounds of polyvinyl chloride (PVC) pipe sold. Revenues from our Manufacturing segment increased $14.5 million, mainly as a result of higher sales volumes from metal parts stamping and fabrication and increased sales of molded plastic horticultural containers. Revenues from our Wind Energy segment increased $4.8 million due to a $21.9 million increase in transportation revenues, mostly offset by a $17.1 million decrease in revenues from the production of wind towers. Revenues from our Health Services segment decreased $9.7 million, mainly due to a reduction in scanning and related services revenue. Food Ingredient Processing revenues decreased $1.7 million, mainly as a result of a 4.7% decrease in the price per pound of product sold.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2010, 2009 and 2008, followed by a discussion of our financial position at the end of 2010 and our outlook for 2011.

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 2010, 2009 and 2008 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)*	2010	2009	2008
Operating Revenues:			
Electric	$ 234	$ 199	$ 292
Nonelectric	6,310	5,207	3,292
Cost of Goods Sold	5,595	4,919	3,141
Other Nonelectric Expenses	949	487	443

ELECTRIC

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

(in thousands)	2010	% change	2009	% change	2008
Retail Sales Revenues	$ 301,080	7	$ 282,116	(2)	$ 287,631
Wholesale Revenues— Company Generation	20,053	59	12,579	(47)	23,708
Net Revenue— Energy Trading Activity	3,144	(1)	3,183	(10)	3,528
Other Revenues	16,036	(4)	16,788	(33)	25,208
Total Operating Revenues	$ 340,313	8	$ 314,666	(7)	$ 340,075
Production Fuel	73,102	23	59,387	(17)	71,930
Purchased Power—System Use	44,788	(15)	52,942	(6)	56,329
Other Operation and Maintenance Expenses	112,174	5	106,457	(8)	116,071
Depreciation and Amortization	40,241	9	36,946	16	31,755
Property Taxes	9,364	6	8,853	(1)	8,949
Operating Income	$ 60,644	21	$ 50,081	(9)	$ 55,041

Electric kwh Sales *(in thousands)*	2010	% change	2009	% change	2008
Retail kwh Sales	4,262,748	—	4,244,377	—	4,241,907
Wholesale kwh Sales— Company Generation	624,153	55	402,498	(15)	472,441
Wholesale kwh Sales— Purchased Power Resold	336,875	(66)	1,004,916	(55)	2,210,188

2010 compared with 2009

The $19.0 million increase in retail sales revenues was due to the following: (1) a $7.4 million increase in resource recovery and transmission rider revenues, (2) a $3.9 million increase in revenues mostly due to a 2.8% increase in kwh sales to retail commercial customers, (3) a $2.5 million increase from interim rates implemented in Minnesota in June 2010, (4) a $1.8 million increase in Minnesota Conservation Improvement Program (CIP) surcharge revenues, (5) a $1.5 million increase related to a South Dakota general rate increase implemented in May 2009, (6) a $0.8 million increase in Fuel Clause Adjustment (FCA) revenues related to an increase in fuel and purchased power costs incurred to serve retail customers, (7) a $0.6 million increase in revenue related to recovery of the North Dakota portion of OTP's Big Stone II plant abandonment costs, and (8) a $0.5 million increase in revenue related to a Minnesota interim rate refund adjustment in 2009.

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

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

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

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

2009 compared with 2008

The main reasons for the $5.5 million decline in retail sales revenue was a $15.5 million decrease in revenues related to a reduction in costs of fuel and purchased power to serve retail customers, a $1.5 million increase in 2008 revenue related to the cost of replacement power purchased in November and December of 2007 when Big Stone Plant was down for maintenance, and a $0.5 million increase in the first quarter of 2009 in a Minnesota interim rate refund. These revenue decreases were partially offset by revenue increases of: (1) $6.6 million in Minnesota and North Dakota renewable resource recovery rider revenues, (2) $3.8 million from a 3.0% general rate increase in North Dakota, approved in November 2009 but effective with interim rates beginning in January 2009, and (3) $1.5 million from an 11.7% general rate increase in South Dakota effective in May 2009 and approved in June 2009. Retail kwh sales grew by only 0.1% between the years.

The $11.1 million decrease in wholesale revenues from company-owned generation was due to a 37.7% decrease in the average price per kwh sold, combined with a 14.8% decrease in wholesale kwh sales. Fuel costs related to wholesale sales decreased $3.7 million between the years as a result of the decrease in wholesale kwh sales combined with reductions in fuel costs and generation at OTP's combustion turbine peaking plants. Reductions in industrial consumption of electricity, declining natural gas prices, increased efficiency in wholesale electric markets and increased generation from renewable wind and hydroelectric resources have driven down prices for electricity in the wholesale market. The $0.3 million decrease in net revenue from energy trading activities, including net mark-to-market gains on forward energy contracts was the result of a reduction in margins on energy trades between the years. Other electric operating revenues decreased $8.4 million as a result of an $8.0 million reduction in revenues from construction and permitting work completed for other entities on regional energy projects and a $0.4 million decrease in revenues from transmission and dispatch related services.

The $12.5 million decrease in production fuel costs reflects a 16.4% decrease in kwhs generated from OTP's fossil fuel-fired plants. Another major factor contributing to the decrease in fuel costs was a 32.6% decrease in kwhs generated from OTP's fuel-oil and natural gas-fired combustion turbines, in combination with lower fuel and natural gas prices. Fuel costs were also reduced as a result of wind turbines owned by OTP providing 10.6% of total kwh generation in 2009 compared with 4.0% in 2008. Generation for retail sales decreased 9.4% while generation used for wholesale electric sales decreased 14.8% between the years.

The $3.4 million decrease in purchased power—system use is due to a 30.8% reduction in the cost per kwh purchased offset by a 35.8% increase in kwhs purchased. The increase in kwh purchases for system use is related to a reduction in the availability of company-owned generation resulting from maintenance outages at Big Stone and Hoot Lake Plants, a six-week scheduled maintenance shutdown of Coyote Station in the second quarter of 2009 and an unplanned outage for generator repairs at Coyote Station in the third quarter of 2009. The decrease in the cost per kwh of purchased power reflects a significant decrease in fuel and purchased power costs across the Mid-Continent Area Power Pool region as a result of reductions in industrial consumption of electricity related to the recent economic recession, lower natural gas prices and the availability of increased generation from renewable wind and hydroelectric sources.

The $9.6 million decrease in other electric operating and maintenance expenses includes: (1) a $7.5 million decrease in costs associated with construction work completed for other entities on regional energy projects, commensurate with an $8.0 million decrease in related revenue, (2) a $1.1 million reduction in external services expenses, for tree trimming and power-plant maintenance, and (3) a $0.9 million reduction in vehicle and travel expenses related to a 37.3% reduction in fuel prices and an increase in vehicle costs capitalized for transportation and equipment used on construction projects in 2009.

The $5.2 million increase in depreciation expense mainly is due to the additions of 32 wind turbines at the Ashtabula Wind Energy Center placed in service at the end of 2008 and 33 wind turbines at the Luverne Wind Farm placed in service in September 2009.

WIND ENERGY

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

(in thousands)	2010	% change	2009	% change	2008
Wind Tower Revenues	$ 143,599	(11)	$ 160,695	(35)	$ 248,994
Transportation Revenues	54,147	68	32,228	(23)	41,838
Total Operating Revenues	$ 197,746	2	$ 192,923	(34)	$ 290,832
Cost of Goods Sold	137,639	6	130,366	(40)	217,134
Operating Expenses	63,231	31	48,118	(14)	55,960
Depreciation and Amortization	11,087	7	10,316	25	8,254
Operating (Loss) Income	$ (14,211)	(445)	$ 4,123	(57)	$ 9,484

2010 compared with 2009

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

- Revenues at DMI Industries, Inc., (DMI), our manufacturer of wind towers, decreased $17.1 million as lower production levels were realized due to a different customer mix and lower productivity while supporting deliveries on a customer contract.
- Revenues at E.W. Wylie Corporation (Wylie), our flatbed trucking company, increased $21.9 million as a result of $10.6 million in revenue earned on a major wind tower transportation project in 2010 and a 15.8% increase in miles driven by company-owned and owner-operated trucks combined with a 12.3% increase in revenue per mile driven, as well as increases in brokerage revenues of $3.4 million. The increase in miles driven reflects increased demand for flatbed and heavy-haul services. The increase in revenue per mile driven reflects higher freight rates and price increases for fuel cost recovery related to a 26.1% increase in the average cost per gallon of fuel consumed.

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

- Cost of goods sold at DMI increased $7.3 million. A reduction in costs related to production decreases was offset by $16.6 million in additional production costs incurred in 2010 to complete towers to a customer's new design specifications and to support the customer's delivery schedule for completed towers.

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

- Operating expenses at DMI decreased $1.2 million as DMI recorded a $0.9 million loss on the sale of fixed assets in 2009 compared to no losses on asset sales in 2010. Also, DMI's insurance expenses decreased $0.4 million as a result of safety improvements.
- Operating expenses at Wylie increased $15.3 million as a result of increases of $10.3 million in contractor services, $2.5 million in fuel costs, $2.1 million in brokerage settlements, $0.7 million in labor and travel costs, and $0.6 million in repairs and maintenance costs. The increase in contractor services costs is mainly due to costs incurred on a major wind tower transportation project in 2010. The remaining expense increases were due to the 15.8% increase in miles driven by company-owned and owner-operated trucks combined with a 26.1% increase in the average cost per gallon of fuel consumed and a 24.8% increase in brokerage miles.

Depreciation expense increased mainly as a result of capital additions at DMI in 2009.

2009 compared with 2008

The decrease in revenues in our Wind Energy segment in 2009 compared with 2008 relates to the following:

- Revenues at DMI decreased $88.3 million as a result of a lower volume of wind towers being sold in 2009
- Revenues at Wylie decreased $9.6 million as a result of a 13.8% reduction in miles driven by company-owned trucks directly related to the recent economic recession combined with the effect of lower diesel fuel prices being passed through to customers. Also, increased competition for fewer loads has driven down shipping rates.

The decrease in cost of goods sold in our Wind Energy segment in 2009 compared with 2008 relates to the following:

- Cost of goods sold at DMI decreased $86.8 million as a result of the reductions in production and sales of wind towers. Also, cost of goods sold in 2008 included $4.3 million in costs associated with start-up inefficiencies at DMI's Oklahoma plant, $3.5 million in additional labor and material costs on a production contract in Ft. Erie and higher costs due to steel surcharges.

The decrease in operating expenses in our Wind Energy segment in 2009 compared with 2008 relates to the following:

- Operating expenses at DMI decreased $2.5 million, reflecting decreases in labor, selling and promotional expenses.
- Wylie's operating expenses decreased $5.3 million between the years. Fuel costs decreased $7.2 million as a result of a 37.6% decrease in fuel costs per gallon combined with the 13.8% decrease in miles driven by company-owned trucks. Payments to owner-operators decreased $1.2 million as a result of lower fuel prices. The decreases in fuel costs were partially offset by an increase in repair and maintenance expenses of $1.7 million, an increase in rent expenses of $1.0 million, mainly related to additional equipment leases, and an increase in labor costs of $0.5 million.

Depreciation expense increased as a result of capital additions at DMI in 2008.

MANUFACTURING

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

(in thousands)	2010	% change	2009	% change	2008
Operating Revenues	$ 178,690	9	$ 164,186	(26)	$ 222,482
Cost of Goods Sold	133,754	2	131,411	(24)	172,360
Other Operating Expenses	26,630	5	25,466	(13)	29,429
Asset Impairment Charge	19,740	—	—	—	—
Product Recall and Testing Costs	—	—	1,625	—	—
Plant Closure Costs	—	—	—	—	2,295
Depreciation and Amortization	12,848	1	12,754	12	11,359
Operating (Loss) Income	$ (14,282)	(102)	$ (7,070)	(200)	$ 7,039

2010 compared with 2009

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

- Revenues at BTD Manufacturing, Inc. (BTD), our metal parts stamping and fabrication company, increased $21.6 million (25.6%) due to improved customer demand and higher scrap-metal prices in 2010.
- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased $2.2 million (6.4%) due to increased sales of horticultural and custom products.
- Revenues at ShoreMaster decreased $9.3 million (20.7%) due to an $11.8 million decrease in commercial sales, partially offset by a $2.5 million increase in sales of residential products.

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

- Cost of goods sold at BTD increased $11.3 million as a result of a $16.2 million increase in labor, material and overhead costs related to higher sales volumes, mitigated by a $4.9 million reduction in costs due to productivity improvements and sales of higher cost finished goods inventory in the first quarter of 2009.
- Cost of goods sold at T.O. Plastics increased $0.4 million as a result of a $1.6 million increase in labor, material and overhead costs related to higher sales volumes, mitigated by a $1.2 million reduction in costs due to productivity improvements.
- Cost of goods sold at ShoreMaster decreased $9.4 million mainly due to the decrease in sales of commercial products, but also due to $1.8 million in additional costs incurred on a commercial project in 2009.

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

- Other operating expenses at BTD decreased $0.3 million mainly as a result of reductions in outside sales commissions paid in 2010.
- Other operating expenses at T.O. Plastics increased $0.6 million mainly due to increased salary and benefit costs related to new hires in engineering and sales positions and to an increase in promotional expenses.
- Other operating expenses at ShoreMaster increased $0.9 million between the periods mainly due to an increase in its provision for uncollectible accounts in 2010.

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

(in thousands)	
Goodwill	$ 12,259
Brand/Trade Name	4,869
Other Intangible Assets	507
Long-Lived Assets	2,105
Total Asset Impairment Charges	$ 19,740

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

2009 compared with 2008

The decrease in revenues in our Manufacturing segment in 2009 compared with 2008 relates to the following:

- Revenues at BTD decreased $30.4 million (26.7%) as a result of decreases of $18.8 million from reduced sales volume, $9.0 million from lower prices and $2.7 million in scrap sales revenue related to lower steel prices and less scrap available for sale.
- Revenues at ShoreMaster decreased $20.8 million (31.7%). The decrease in revenues mainly reflects a lower volume of commercial construction projects in 2009 and lower sales of residential products between the years related to the economic recession and credit restraints affecting consumers.
- Revenues at T.O. Plastics decreased $7.0 million (16.8%) due to a decrease in volume of products sold, mainly as a result of delays in, or suspension of, orders related to the economic recession. Revenues in 2008 included $1.7 million from a small facility in South Carolina that was sold in 2008.

The decrease in cost of goods sold in our Manufacturing segment in 2009 compared with 2008 relates to the following:

- Cost of goods sold at BTD decreased $17.3 million. A decrease of $13.7 million in cost of goods sold related to a decrease in sales volume and $7.0 million in lower prices for raw materials was partially offset by $3.3 million in unabsorbed overhead costs due to the lower volume of products produced and sold.
- Cost of goods sold at ShoreMaster decreased $17.5 million mainly due to the completion of a large commercial construction project in 2008 and reduced sales of residential products between the years.
- Cost of goods sold at T.O. Plastics decreased $6.1 million mainly as a result of a decrease in volume of products sold.

The decrease in operating expenses in our Manufacturing segment in 2009 compared with 2008 relates to the following:

- Operating expenses at BTD decreased $1.6 million mainly due to a reduction in incentive compensation directly related to decreased profitability between the years.
- Operating expenses at ShoreMaster decreased $3.0 million, which reflects a reduction of $2.3 million mainly in payroll costs and selling expenses and $2.3 million in plant closure costs incurred in 2008, offset by $1.6 million of product recall and testing costs incurred in 2009. The $2.3 million in plant closure costs in 2008 includes employee-related termination obligations, asset impairment costs and other losses and expenses incurred related to the shutdown and sale of a production facility in California following the completion of a major marina project in the state. The $1.6 million in product recall and testing costs in 2009 includes the recognition of $1.1 million in costs related to the recall of certain trampoline products and $0.5 million in costs to test imported products for lead and phthalate content.
- Operating expenses at T.O. Plastics were flat between the years.

Depreciation expense increased as a result of the acquisition of Miller Welding & Iron Works, Inc. in May 2008.

CONSTRUCTION

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

(in thousands)	2010	% change	2009	% change	2008
Operating Revenues	$ 134,222	29	$ 103,831	(34)	$ 157,053
Cost of Goods Sold	120,470	36	88,429	(33)	132,927
Operating Expenses	12,235	8	11,311	(10)	12,544
Depreciation and Amortization	2,023	1	2,010	7	1,877
Operating (Loss) Income	$ (506)	(124)	$ 2,081	(79)	$ 9,705

2010 compared with 2009

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

- Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, increased $29.0 million (45.3%) due to an increase in construction activity.
- Revenues at Aevenia, Inc. (Aevenia), our electrical design and construction services company, increased $1.4 million (3.5%) as a result of an increase in electrical underground and substation work, partially offset by reductions in work on overhead line construction and wind generation projects in 2010.

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

- Cost of goods sold at Foley increased $30.2 million as a result of an increase in the size and volume of jobs in progress in 2010.
- Cost of goods sold at Aevenia increased $1.8 million, mainly due to an increase in work volume.

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

- Operating expenses at Foley increased $0.7 million between the periods mainly for salaries, maintenance and insurance.
- Operating expenses at Aevenia increased $0.2 million due to a decrease in gains on sales of assets and an increase in advertising and promotional expenses in 2010.

2009 compared with 2008

The decrease in revenues in our Construction segment in 2009 compared with 2008 relates to the following:

- Revenues at Foley decreased $34.4 million (35.0%) due to a decrease in volume of jobs in progress related to the recent economic recession and increased competition for available work.
- Revenues at Aevenia decreased $18.8 million (32.1%) as a result of a decrease in jobs in progress, especially wind-energy projects, related to the recent economic recession and increased competition for available work.

The decrease in cost of goods sold in our Construction segment in 2009 compared with 2008 relates to the following:

- Foley's cost of goods sold decreased $31.8 million as a result of decreases in construction activity and jobs in progress.
- Cost of goods sold at Aevenia decreased $12.7 million as a result of a reduction of jobs in progress.

The decrease in operating expenses in our Construction segment in 2009 compared with 2008 relates to the following:

- Aevenia's operating expenses decreased $0.9 million between the years as a result of reductions in employee incentive bonuses and benefits from reduced profitability between the years and reductions in other contracted services related to less work volume.
- Foley's operating expenses decreased $0.3 million between the periods due to reductions in incentive bonuses because of lower profitability in 2009.

PLASTICS

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

(in thousands)	2010	% change	2009	% change	2008
Operating Revenues	$ 96,945	21	$ 80,208	(31)	$ 116,452
Cost of Goods Sold	82,866	15	71,872	(31)	104,186
Operating Expenses	5,174	9	4,764	(4)	4,956
Depreciation and Amortization	3,430	16	2,945	(3)	3,050
Operating Income	$ 5,475	773	$ 627	(85)	$ 4,260

2010 compared with 2009

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

2009 compared with 2008

The $36.2 million decrease in Plastics operating revenues in 2009 compared with 2008 was due to a 9.5% decrease in pounds of pipe sold combined with a 24.0% decrease in the price per pound of pipe sold. The $32.3 million decrease in costs of goods sold was due to the decrease in pounds of pipe sold and a 23.8% decrease in the cost per pound of pipe sold. Beginning in 2008, significant reductions in new home construction in markets served by the plastic pipe companies resulted in reduced demand and lower prices for PVC pipe products.

HEALTH SERVICES

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

(in thousands)	2010	% change	2009	% change	2008
Operating Revenues	$ 100,301	(9)	$ 110,006	(10)	$ 122,520
Cost of Goods Sold	75,203	(16)	89,315	(7)	96,349
Operating Expenses	17,751	(11)	19,844	(6)	21,030
Depreciation and Amortization	5,840	49	3,907	(5)	4,133
Operating Income (Loss)	$ 1,507	149	$ (3,060)	(404)	$ 1,008

2010 compared with 2009

The $9.7 million decrease in Health Services operating revenues reflects an $11.7 million decrease in revenues from scanning and other related services as a result of a 16.8% decrease in scans performed, partially offset by a 2.4% increase in revenue per scan. Revenues from equipment sales increased $2.0 million between the years. The $14.1 million decrease in costs of goods sold reflects a $1.6 million reduction in service labor costs and a reduction in equipment rental costs of $12.5 million directly related to efforts by the Health Services segment to right-size its fleet of imaging assets by exercising purchase options on productive imaging assets coming off lease in 2010 and not renewing leases on underutilized imaging assets. Through this process, the imaging business has reduced the combined number of units of imaging equipment it leases and owns by 16.1% in 2010. The $2.1 million decrease in operating expenses includes reductions in salaries, marketing, travel and rent expenses and a reduction in gains on sales of fixed assets. The $1.9 million increase in depreciation expense reflects an increase in owned equipment compared with a year ago.

2009 compared with 2008

The $12.5 million decrease in Health Services operating revenues reflects a $9.5 million decrease in revenues from scanning and other related services due to a 33.1% decrease in scans and a $3.7 million decrease in rental revenue. Revenues from equipment sales and servicing decreased $3.0 million mainly due to a continued reduction in dealership distribution of products and declining film sales. The $7.0 million decrease in cost of goods sold was directly related to the decreases in sales revenue, but was negatively impacted by higher-than-expected service and maintenance costs in the third quarter of 2009. The $1.2 million decrease in operating expenses is the result of measures taken to control and reduce operating expenses. Also, operating expenses in 2008 are net of a $1.1 million pre-tax gain on the sale of fixed assets. The imaging side of the business was affected by less-than-optimal utilization of certain imaging assets.

FOOD INGREDIENT PROCESSING

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

(in thousands)	2010	% change	2009	% change	2008
Operating Revenues	$ 77,412	(2)	$ 79,098	21	$ 65,367
Cost of Goods Sold	56,619	(4)	58,718	6	55,415
Operating Expenses	3,939	4	3,796	27	2,998
Depreciation and Amortization	4,703	9	4,333	6	4,094
Operating Income	$ 12,151	(1)	$ 12,251	328	$ 2,860

2010 compared with 2009

The $1.7 million decrease in Food Ingredient Processing operating revenues is due to a 4.7% decrease in the price per pound of product sold, partially offset by a 2.7% increase in pounds of product sold as a result of increased customer demand. The $2.1 million decrease in cost of goods sold was the result of a 6.1% decrease in the cost per pound of product sold mainly due to a decrease in raw potato costs. The $0.1 million increase in operating expenses is mainly due to increases in selling and marketing expenses. The $0.4 million increase in depreciation expense is related to 2009 and 2010 capital additions.

2009 compared with 2008

The $13.7 million increase in Food Ingredient Processing operating revenues is due to a 6.6% increase in pounds of product sold, combined with a 13.5% increase in the price per pound of product sold. A $3.3 million increase in cost of goods sold was due to increased product sales, slightly mitigated by a 0.6% decrease in the cost per pound of product sold as a result of decreases in raw potato costs and natural gas prices. Also, increased production and sales resulted in a decrease in overhead absorption costs per pound of product produced and sold. The $0.8 million increase in operating expenses is mostly due to an increase in incentive pay directly related to increased sales and improved operating results in 2009.

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)	2010	% change	2009	% change	2008
Operating Expenses	$ 15,741	19	$ 13,246	(17)	$ 15,867
Depreciation and Amortization	524	32	397	(26)	538

2010 compared with 2009

Corporate operating expenses increased $2.5 million as a result of severance costs related to personnel changes and a reduction in corporate costs allocated to OTP in 2010.

2009 compared with 2008

Corporate operating expenses decreased $2.6 million as a result of reductions for salaries and benefits, including health care expenses and insurance costs.

CONSOLIDATED OTHER INCOME

Other income increased $0.6 million in 2010 compared with 2009 as a result of: (1) a $4.0 million increase in Minnesota CIP accrued incentives at OTP in 2010, offset by (2) a $3.2 million decrease in Allowance for Funds Used During Construction (AFUDC) related to a decrease in construction work in progress at OTP as a result of not having a major project under construction in 2010 similar to the Luverne Wind Farm project in 2009, and (3) a $0.2 million goodwill impairment write off related to a reduction in the fair value of a mechanical and HVAC contracting firm owned by Otter Tail Energy Services Company (OTESCO).

Other income increased by $0.4 million in 2009 compared with 2008 as a result of an increase in AFUDC at OTP in 2009.

CONSOLIDATED INTEREST CHARGES

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

Interest charges increased $1.6 million in 2009 compared with 2008 as a result of the following: (1) the issuance of $75 million in debt in May 2009 to finance construction of OTP's 33 wind turbines at the Luverne Wind Farm, (2) an increase in the interest rate on our $50 million senior unsecured note due November 30, 2017, from 5.778% to 8.89%, in connection with our change to a holding company structure effective July 1, 2009, (3) the issuance of $100 million in debt in December 2009 to pay down line of credit borrowings that were used to finance plant expansions and acquisitions at our nonelectric subsidiaries, (4) increases in the amortization of debt issuance costs related to 2009 debt issuances, and (5) a $0.9 million reduction in capitalized interest charges related to a reduction in the average balance of construction work in progress and short-term debt between the years. These increases in interest charges were partially offset by reductions in interest paid on short-term borrowings as the average daily balance of short-term debt outstanding decreased by $24.4 million and the weighted-average rate of interest on short-term borrowings decreased by 1.7 percentage points between the years.

CONSOLIDATED INCOME TAXES

We recorded $4.0 million in income tax expense in 2010 compared with an income tax benefit of $4.6 million in 2009. The increase in income taxes reflects: (1) the establishment of a $5.5 million valuation allowance against deferred tax assets related to tax operating loss carryforwards of DMI's Canadian operations, (2) a $3.1 million reduction in 2009 income taxes related to a permanent difference in the depreciable tax value of OTP's Luverne Wind Farm assets, (3) a $1.7 million charge to income tax expense related to a change in the tax treatment of postretirement prescription drug benefits under 2010 federal healthcare legislation, and (4) a $1.1 million reversal of deferred tax assets at DMI related to a reduction in Canadian statutory tax rates, offset by (5) a $6.2 million increase in taxable income between the years. Although our income before income taxes decreased in 2010 compared with 2009, $9.4 million of ShoreMaster's 2010 goodwill impairment and a $3.2 million reduction in the electric segment's AFUDC income generated no tax savings in 2010.

The $19.6 million (130.6%) decrease in income taxes in 2009 compared with 2008 is mainly due to three items: (1) a $28.7 million decrease in income before income taxes in 2009 compared with 2008, (2) a permanent difference in the depreciable tax value of OTP's Luverne Wind Farm assets of $15 million, which resulted in a $3.1 million reduction in our consolidated income taxes in 2009, and (3) the benefits of federal production tax credits and North Dakota wind energy credits related to OTP's wind projects of approximately $7.4 million in 2009 compared with $3.6 million in 2008.

Federal production tax credits 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. Income tax reductions from federal production tax credits and North Dakota wind energy credits are passed back to OTP's retail electric customers through reductions to renewable resource recovery riders or renewable energy costs recovered in general rates.

IMPACT OF INFLATION

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

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

LIQUIDITY

The following table presents the status of our lines of credit as of December 31, 2010 and December 31, 2009:

(in thousands)	Line Limit	In Use on December 31, 2010	Restricted due to Outstanding Letters of Credit	Available on December 31, 2010	Available on December 31, 2009
Otter Tail Corporation Credit Agreement	$ 200,000	$ 54,176	$ 1,474	$ 144,350	$ 179,755
OTP Credit Agreement	170,000	25,314	250	144,436	167,735
Total	$ 370,000	$ 79,490	$ 1,724	$ 288,786	$ 347,490

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

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. On March 17, 2010, we entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million. Equity or debt financing will be required in the period 2011 through 2015 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

Our dividend payout ratio has exceeded 100% in each of the last three years. The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share to levels in excess of the indicated annual dividend per share of $1.19, cash flows from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects. The decision to declare a quarterly dividend is reviewed quarterly by the Board of Directors.

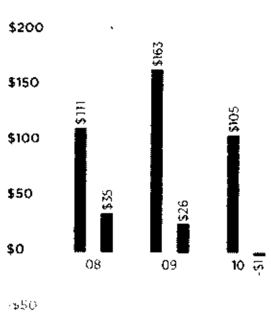
DMI is party to a $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement, originally scheduled to expire in March 2011, was extended for one year by DMI in February 2011. The discount rate for the one-year extension has been increased to 3-month LIBOR plus 4%. Accounts receivable totaling $62.7 million were sold in 2010 compared with $133.9 million in 2009. Discounts, fees and commissions charged to operating expense for the years ended December 31, 2010 and 2009 were $0.2 million and $0.4 million, respectively. The balance of receivables sold that was outstanding to the buyer as of December 31, 2010 was $21.3 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in our consolidated balance sheets and the proceeds are included in the cash flows from operating activities in our consolidated statement of cash flows.

Cash provided by operating activities was $105.0 million in 2010 compared with $162.7 million in 2009. The $57.7 million decrease in cash from operating activities reflects a $27.9 million decrease in reductions of deferred income taxes, a $16.0 million increase in discretionary pension plan contributions and a $12.8 million reduction in cash from changes in working capital items between the years. Major sources of funds from working capital items in 2010 were a $44.1 million reduction in income taxes receivable, mainly related to the receipt of income tax refunds in 2010, and a $31.5 million increase in payables and other current liabilities related to an increase in business activity across all of our operating companies. These increases in cash from working capital items were mostly offset by increases in receivables, inventories and other current assets of $70.6 million, also related to the increase in business activity.

Net cash used in investing activities was $85.2 million in 2010 compared with $147.7 million in 2009. Cash used for capital expenditures decreased by $61.4 million between the years mainly due to reductions in capital expenditures at OTP. A $72.9 million reduction in cash used for capital expenditures net of the $30.2 million in grant proceeds OTP received under the American Recovery and Reinvestment Act of 2009 related to its investment in renewable energy is the result of OTP not having a major construction project in 2010 similar to its Luverne Wind Farm project in 2009. Capital expenditures in the Health Services segment increased $18.5 million in 2010 compared with 2009, as the imaging business continued its asset reduction plan by not renewing leases on assets but instead purchasing productive assets coming off lease or replacing productive leased assets with purchased assets. Cash used for capital expenditures in our Wind Energy segment decreased $8.2 million between the years.

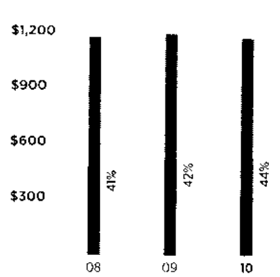
Net cash used in financing activities was $23.7 million in 2010 compared with $17.1 million in 2009. Proceeds from short-term borrowings and checks issued in excess of cash were $81.8 million in 2010 compared with a reduction in short-term borrowings of $127.3 million in 2009. In 2010, OTP paid off the remaining $58.0 million balance outstanding on its two-year, $75.0 million term loan that was originally due on May 20, 2011, using lower costs funds available under the OTP Credit Agreement. OTP borrowed the $75.0 million in May 2009 to support its construction of 49.5 megawatts (MW) of renewable wind-generation assets at the Luverne Wind Farm. In December 2009 we issued $100 million of our 9.000% notes due 2016. Proceeds from the issuance were used to repay our revolving credit facility, which had an outstanding balance due of $107.0 million on November 30, 2009 at an interest rate of approximately 2.6%.

CASH REALIZATION (millions)



■ Cash flows from operations
■ Net income

INTEREST-BEARING DEBT AS A PERCENT OF TOTAL CAPITAL (millions)



We have maintained a 40-45% interest-bearing debt to total capital ratio for the past three years.

■ Total capital
■ Interest-bearing debt (includes 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, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, purchase of diagnostic medical equipment, transportation equipment 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 $86 million in 2010, $177 million in 2009 and $266 million in 2008. Estimated capital expenditures for 2011 are $109 million. Total capital expenditures for the five-year period 2011 through 2015 are estimated to be approximately $956 million, which includes $264 million for OTP's share of a new air quality control system at Big Stone Plant and $188 million for new transmission projects including $130 million for CapX2020 transmission projects.

The breakdown of 2008, 2009 and 2010 actual and 2011 through 2015 estimated capital expenditures by segment is as follows:

(in millions)	2008	2009	2010	2011	2011-2015
Electric	$ 198	$ 146	$ 43	$ 67	$ 724
Wind Energy	38	12	4	12	54
Manufacturing	11	8	7	9	47
Construction	3	2	5	7	25
Plastics	9	4	3	2	9
Health Services	4	3	22	10	79
Food Ingredient Processing	3	1	1	2	17
Corporate	—	1	1	—	1
Total	$ 266	$ 177	$ 86	$ 109	$ 956

The following table summarizes our contractual obligations at December 31, 2010 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1–3 Years	3–5 Years	More than 5 Years
Long-Term Debt Obligations	$ 436	$ 91	$ 14	$ —	$ 331
Interest on Long-Term Debt Obligations	271	30	49	49	143
Capacity and Energy Requirements	165	20	38	28	79
Coal Contracts (required minimums)	116	47	45	20	4
Operating Lease Obligations	87	26	26	12	23
Postretirement Benefit Obligations	70	3	8	8	51
Other Purchase Obligations	19	19	—	—	—
Total Contractual Cash Obligations	$ 1,164	$ 236	$ 180	$ 117	$ 631

Interest on $10.4 million of variable-rate debt outstanding on December 31, 2010 was projected based on the interest rates applicable to that debt instrument on December 31, 2010. Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan as we are not currently required to make a contribution to that plan.

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings, and alternative financing arrangements such as leasing. Equity or debt financing will be required in the period 2011 through 2015 given the expansion plans related to our Electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

On May 11, 2009 we filed a shelf registration statement with the Securities and Exchange Commission under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement.

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

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2010 and December 31, 2009:

(in thousands)	Line Limit	In Use on December 31, 2010	Restricted due to Outstanding Letters of Credit	Available on December 31, 2010	Available on December 31, 2009
Otter Tail Corporation Credit Agreement	$ 200,000	$ 54,176	$ 1,474	$ 144,350	$ 179,755
OTP Credit Agreement	170,000	25,314	250	144,436	167,735
Total	$ 370,000	$ 79,490	$ 1,724	$ 288,786	$ 347,490

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

OTP is the borrower under a $170 million credit agreement (the OTP Credit Agreement) with an accordion feature whereby the line can be increased to $250 million as 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 $50,000,000 outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP pays utilization fees when usage of the revolving credit facility exceeds 50% of the commitments of the lenders and pays facility fees based on the average daily amount outstanding under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower's credit ratings. The OTP Credit Agreement is subject to renewal on July 30, 2011. We are in the process of renewing the OTP Credit Agreement and have signed a term sheet with an agent bank. The term sheet calls for a five-year term facility with borrowings priced at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP's senior unsecured debt. All other terms in the term sheet are substantially the same as in the current OTP Credit Agreement. We expect the new OTP credit agreement to be completed and closed in March of 2011.

Long-Term Debt

OTP's Senior Unsecured Notes 6.63% due December 1, 2011 remain classified as long-term debt because OTP has the ability to refinance this debt under the OTP Credit Agreement scheduled for renewal in July 2011.

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

In June 2009, the Company paid $3,493,000 to retire early its Lombard US Equipment Finance note due October 2, 2010. No penalty was paid for early retirement of the note.

Prior to our holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $75 million term loan agreement (the OTP Loan Agreement). The OTP Loan Agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein. On completion of the Company's holding company formation on July 1, 2009, the OTP Loan Agreement became an obligation of OTP. The OTP Loan Agreement provided for a $75 million term loan due May 20, 2011. The proceeds were used to support OTP's construction of 49.5 MW of renewable wind-generation assets at the Luverne Wind Farm. In November 2009, OTP paid down $17 million of the $75 million term loan. OTP paid off the remaining $58 million balance in January 2010, using lower cost funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayments and retirement of its debt under the OTP Loan Agreement.

The note purchase agreement relating to OTP's $90 million 6.63% senior notes due December 1, 2011, as amended (the 2001 Note Purchase Agreement), the note purchase agreement relating to our $50 million 8.89% senior note due November 30, 2017, as amended (the Cascade Note Purchase Agreement), and 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) each states that the applicable obligor may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the applicable obligor to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states the applicable obligor 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 such obligor. The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement each contain a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor's ability and the ability of the obligor's subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Our obligations under the Cascade Note Purchase Agreement are guaranteed by certain of our material subsidiaries. Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2010.

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

Financial Covenants

As of December 31, 2010 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:

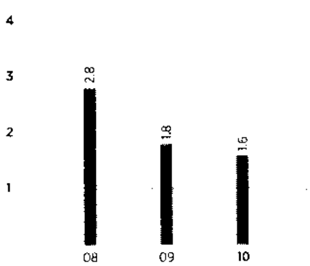
- Under the Credit Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), as provided in the Credit Agreement. As of December 31, 2010 our Interest and Dividend Coverage Ratio calculated under the requirements of the Credit Agreement was 1.70 to 1.00.
- Under the Cascade Note Purchase Agreement, we may not permit our ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or our Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement. As of December 31, 2010 our Interest Charges Coverage Ratio calculated under the requirements of the Cascade Note Purchase Agreement was 1.60 to 1.00.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the OTP Credit Agreement. As of December 31, 2010 OTP's Interest and Dividend Coverage Ratio calculated under the requirements of the OTP Credit Agreement was 3.18 to 1.00.

- Under the 2001 Note Purchase Agreement, the 2007 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 (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges 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 2001 Note Purchase Agreement and the 2007 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, 2010 OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement, respectively, was 3.18 to 1.00.

As of December 31, 2010 our interest-bearing debt to total capitalization was 0.44 to 1.00 on a fully consolidated basis and 0.49 to 1.00 for OTP.

Our ratio of earnings to fixed charges from continuing operations, which includes imputed finance costs on operating leases, was 1.1x for 2010 compared to 1.6x for 2009, and our debt interest coverage ratio before taxes was 1.6x for 2010 compared to 1.8x for 2009. During 2011, we expect these coverage ratios to increase, assuming 2011 net income meets our expectations.

DEBT INTEREST COVERAGE
(times interest earned before tax)



Otter Tail has maintained coverage ratios in excess of its debt covenant requirements.

OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $9.6 million, but our line of credit borrowing limits are only restricted by $1.7 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.

2011 BUSINESS OUTLOOK

We anticipate 2011 diluted earnings per share to be in the range of $1.00 to $1.40. This guidance considers the cyclical nature of some of our businesses and reflects challenges presented by current economic conditions and our plans and strategies for improving future operating results. Our current consolidated capital expenditures expectation for 2011 is in the range of $100 million to $110 million. This compares with $86 million of capital expenditures in 2010. We continue to explore investments in generation and transmission projects for the Electric segment that could have positive impacts on our earnings and returns on capital.

Segment components of the corporation's 2011 earnings per share guidance range are as follows:

	EPS Range Low	High
Electric	$ 0.97	$ 1.02
Wind Energy	(0.10)	0.05
Manufacturing	0.13	0.18
Construction	0.05	0.08
Plastics	0.05	0.08
Health Services	0.00	0.04
Food Ingredient Processing	0.17	0.20
Corporate	(0.27)	(0.25)
Totals	$ 1.00	$ 1.40

Contributing to our earnings guidance for 2011 are the following items:

- We expect an increase in net income from our Electric segment in 2011. This is based on anticipated sales growth and rate and rider recovery increases, an increase in capitalized interest costs related to larger construction expenditures and reductions in operating and maintenance expense in 2011 due to lower benefit costs.
- We expect improved operations from our Wind Energy segment in 2011. Lost productivity incurred to meet a customer's design specifications and delivery schedule on a new tower design in 2010 are not expected to be repeated in 2011. Backlog in the Wind Energy segment is $157 million for 2011 compared with $176 million one year ago.
- We expect earnings from our Manufacturing segment to improve significantly in 2011 as a result of the following:
  - Improved earnings are expected at BTD in 2011 based on an expectation of improving economic conditions in the industries BTD serves and increased order volume.
  - Expected near breakeven performance at ShoreMaster in 2011 as a result of bringing costs in line with current revenue levels and not incurring a $15.6 million net-of-tax noncash impairment charge similar to 2010.
  - Slightly better earnings are expected at T. O. Plastics in 2011 compared with 2010.
  - Backlog of approximately $86 million in place in the Manufacturing segment to support 2011 revenues compared with $63 million one year ago.
- We expect higher net income from our Construction segment in 2011 as the economy improves and the construction companies record earnings on a higher volume of jobs in progress. Backlog in place for the construction businesses is $164 million for 2011 compared with $84 million one year ago.
- We expect our Plastics segment's 2011 performance to be in line with 2010 results.
- We expect increased net income from our Health Services segment in 2011 as the benefits of implementing its asset reduction plan continue to be realized.
- We expect a reduction in net income from our Food Ingredient Processing segment in 2011 compared with the record earnings achieved in 2010.
- Corporate general and administrative costs are expected to decrease in 2011 as a result of reductions in employee count and benefits.

Our outlook for 2011 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 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, service contract maintenance costs, percentage-of-completion 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 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 2011 for our noncontributory funded pension plan is expected to be $6.3 million compared to $5.7 million in 2010, reflecting a reduction in the assumed rate of return on pension plan assets from 8.5% in 2010 to 8.0% in 2011. The estimated discount rate used to determine annual benefit cost accruals will be 6.00% in 2011, the same rate as in 2010. 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 2010, all other factors being held constant: a 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2010 pension benefit cost by $500,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2010 pension benefit cost by $500,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2010 pension benefit cost by $515,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2010 pension benefit cost by $405,000.

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 (or decrease) in the discount rate would have decreased (or increased) our 2010 postretirement medical benefit costs by $10,000. See note 12 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

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

Revenue Recognition

DMI, ShoreMaster and our construction companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours at DMI, and costs incurred to total estimated costs on all other construction projects. The duration of the majority of these contracts is less than a year. Revenues recognized on jobs in progress as of December 31, 2010 were $491 million. Any expected losses on jobs in progress at year-end 2010 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

Forward Energy Contracts Classified as Derivatives

OTP's forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under generally accepted accounting principles. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models and, as such, are estimates. The forward energy sales contracts that are marked to market as of December 31, 2010, are 100% offset by forward energy purchase contracts in terms of volumes and delivery periods but not in terms of delivery points. The differential in forward prices at the different delivery locations currently results in a net mark-to-market unrealized gain on OTP's open forward contracts. OTP's recognized but unrealized net gains of $763,000 on forward purchases and sales of electricity marked to market on December 31, 2010 are expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	1st Qtr 2011	2nd Qtr 2011	3rd Qtr 2011	4th Qtr 2011	2012	**Total**
Net Gain	$ 97	$ 102	$ 140	$ 103	$ 321	$ 763

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 2010, $4.2 million of bad debt expense (0.4% of total 2010 revenue of $1.1 billion) was recorded and the allowance for doubtful accounts was $6.9 million (4.8% of trade accounts receivable) as of December 31, 2010. 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, 2010 would result in a $1.4 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 65 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 3.01% in 2010, 2.90% in 2009 and 2.81% in 2008. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

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

Taxation

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2010 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of Accounting Standards Codification (ASC) 740, *Income Taxes*, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

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

Asset Impairment

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

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

As of December 31, 2010 an assessment of the carrying amounts of our long-lived assets and other intangibles indicated these assets were not impaired.

Goodwill Impairment

Goodwill is required to be evaluated annually for impairment, according to ASC 350-20-35, *Goodwill—Subsequent Measurement*. 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 evaluate goodwill for impairment on an annual basis and as conditions warrant. In 2010, goodwill impairments were recorded at ShoreMaster and OTESCO. See note 1 to our consolidated financial statements for details. An assessment of the carrying amounts of our remaining goodwill as of December 31, 2010 indicated the fair values of our remaining reporting units are substantially in excess of their respective book values and not impaired.

Acquisition Method of Accounting

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

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

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

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2010 we had exposure to market risk associated with interest rates because we had $54.2 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 3.25% under our $200 million revolving credit facility and $25.3 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under OTP's $170 million revolving credit facility. At December 31, 2010 we had exposure to changes in foreign currency exchange rates. DMI has market risk related to changes in foreign currency exchange rates at its plant in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 18.0% of IPH sales in 2010 were outside the United States and the Canadian operation of IPH pays its operating expenses in Canadian dollars.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of December 31, 2010 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2010, annualized interest expense and pre-tax earnings would change by approximately $104,000.

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

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

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

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2010 OTP had recognized, on a pretax basis, $763,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy sales contracts that are marked to market as of December 31, 2010, are 100% offset by forward energy purchase contracts in terms of volumes, delivery periods but not in terms of delivery points. The differential in forward prices at the different delivery locations currently results in a mark-to-market unrealized gain on OTP's open forward contracts.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with our energy trading activities. Additionally, we have a Value at Risk (VaR) limit to further manage market price risk. There was price risk on open positions as of December 31, 2010 because the open purchases were not at the same delivery points as the open sales.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on the Company's consolidated balance sheets as of December 31, 2010 and December 31, 2009, and the change in the Company's consolidated balance sheet position from December 31, 2009 to December 31, 2010 and December 31, 2008 to December 31, 2009:

(in thousands)	**December 31, 2010**	December 31, 2009
Current Asset—Marked-to-Market Gain	$ 6,875	$ 8,321
Regulatory Asset— Deferred Marked-to-Market Loss	12,054	7,614
Total Assets	18,929	15,935
Current Liability—Marked-to-Market Loss	(17,991)	(14,681)
Regulatory Liability— Deferred Marked-to-Market Gain	(175)	(224)
Total Liabilities	(18,166)	(14,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 763	$ 1,030

(in thousands)	**Year Ended December 31, 2010**	Year Ended December 31, 2009
Fair Value at Beginning of Year	$ 1,030	$ (123)
Amount Realized on Contracts Entered into in Prior Year	389	123
Changes in Fair Value of Contracts Entered into in Prior Year	—	—
Net Fair Value of Contracts Entered into in Prior Year at Year End	641	—
Changes in Fair Value of Contracts Entered into in Current Year	122	1,030
Net Fair Value at End of Year	$ 763	$ 1,030

The $763,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2010 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	1st Qtr 2011	2nd Qtr 2011	3rd Qtr 2011	4th Qtr 2011	2012	Total
Net Gain	$ 97	$ 102	$ 140	$ 103	$ 321	$ 763

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, 2010 was $585,000. As of December 31, 2010 OTP had a net credit risk exposure of $1,129,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2010 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The $1,129,000 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, 2010. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able to increase prices for its finished products to recover increases in fuel costs. In order to limit its exposure to fluctuations in future prices of natural gas, IPH entered into contracts with a fuel supplier in September 2010 for firm purchases of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho through September 2011 at fixed prices. These contracts qualify for the normal purchase exception to mark-to-market accounting under ASC 815-10-15, *Derivatives and Hedging*.

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. IPH's Canadian subsidiary also entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in July 2009. Each monthly contract was for the exchange of $200,000 U.S. dollars for the amount of Canadian dollars stated in each contract. All contracts entered into in 2008 and 2009 were settled as of December 31, 2009. IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in May 2010 to cover the majority of its Canadian dollar cash needs from June 2010 through December 2010. Each contract was for the exchange of $250,000 U.S. dollars for the amount of Canadian dollars stated in each contract.

The following table lists the contracts entered into in 2008 and 2009 that were settled in 2009 and the contracts entered into in 2010 that were settled in 2010:

(in thousands)	Settlement Periods	USD	CAD
Contracts Entered Into in July 2008	January 2009–July 2009	$2,800	$2,918
Mark-to-Market Losses on Open Contracts at Year End 2008	January 2009–July 2009	(401)	
Contracts Entered Into in October 2008	January 2009–October 2009	$4,000	$5,001
Mark-to-Market Gains on Open Contracts at Year End 2008	January 2009–October 2009	112	
Net Mark-to-Market Losses Recognized on Open Contracts at Year End 2008		$ (289)	
Net Mark-to-Market Gains in 2009 on Open Contracts at Year End 2008		232	
Net Losses Realized on Settlement of 2008 Contracts in 2009		$ (57)	
Contracts Entered Into in July 2009	August 2009–December 2009	$1,000	$1,163
Net Mark-to-Market Gains Recognized and Realized on Contracts Entered Into in 2009		$ 88	
Net Mark-to-Market Gains Recognized in 2009		$ 320	
Net Mark-to-Market Gains Realized in 2009		$ 31	
Contracts Entered Into in May 2010	June 2010–December 2010	$4,500	$4,680
Net Mark-to-Market Gain Recognized and Realized on Contracts Entered Into in 2010		$ 35	

These contracts are derivatives subject to mark-to-market accounting. IPH did not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates. IPH settled these contracts during their stated settlement periods and used the proceeds to pay its Canadian liabilities when they came due. These contracts do not qualify for hedge accounting treatment because the timing of their settlements did not coincide with the payment of specific bills or contractual obligations. There were no foreign currency exchange forward windows outstanding as of December 31, 2010 or December 31, 2009.

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, 2010 and 2009, and the related consolidated statements of income, common shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2010. We also have audited the Company's internal control over financial reporting as of December 31, 2010 based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 25, 2011

Consolidated Statements of Income—For the Years Ended December 31

(in thousands, except per-share amounts)	2010	2009	2008
Operating Revenues			
Electric	$ 340,078	$ 314,467	$ 339,783
Nonelectric	779,006	725,045	971,414
Total Operating Revenues	1,119,084	1,039,512	1,311,197
Operating Expenses			
Production Fuel—Electric	73,102	59,387	71,930
Purchased Power—Electric System Use	44,788	52,942	56,329
Electric Operation and Maintenance Expenses	112,174	106,457	116,071
Cost of Goods Sold—Nonelectric (excludes depreciation; included below)	600,956	565,192	775,229
Other Nonelectric Expenses	143,751	126,058	142,342
Asset Impairment Charge	19,740	—	—
Product Recall and Testing Costs	—	1,625	—
Plant Closure Costs	—	—	2,295
Depreciation and Amortization	80,696	73,608	65,060
Property Taxes—Electric	9,364	8,853	8,949
Total Operating Expenses	1,084,571	994,122	1,238,205
Operating Income	34,513	45,390	72,992
Other Income	5,126	4,550	4,128
Interest Charges	37,032	28,514	26,958
Income Before Income Taxes	2,607	21,426	50,162
Income Tax Expense (Benefit)	3,951	(4,605)	15,037
Net Income (Loss)	(1,344)	26,031	35,125
Preferred Dividend Requirements and Other Adjustments	833	736	736
Earnings (Loss) Available for Common Shares	$ (2,177)	$ 25,295	$ 34,389
Average Number of Common Shares Outstanding—Basic	35,784	35,463	31,409
Average Number of Common Shares Outstanding—Diluted	35,784	35,717	31,673
Earnings (Loss) Per Common Share:			
Basic	$ (0.06)	$ 0.71	$ 1.09
Diluted	$ (0.06)	$ 0.71	$ 1.09
Dividends Per Common Share	$ 1.19	$ 1.19	$ 1.19

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheets, December 31

(in thousands)	2010	2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ —	$ 4,432
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $6,910 for 2010 and $4,391 for 2009)	135,966	95,747
Other	19,399	10,883
Inventories	95,016	86,515
Deferred Income Taxes	11,219	11,457
Accrued Utility and Cost-of-Energy Revenues	16,323	15,840
Costs and Estimated Earnings in Excess of Billings	67,352	61,835
Income Taxes Receivable	2,291	48,049
Other	21,866	15,265
Total Current Assets	369,432	350,023
Investments	9,708	9,889
Other Assets	27,356	26,098
Goodwill	94,066	106,778
Other Intangibles—Net	27,132	33,887
Deferred Debits		
Unamortized Debt Expense	6,444	7,625
Regulatory Assets and Other Deferred Debits	127,766	121,751
Total Deferred Debits	134,210	129,376
Plant		
Electric Plant in Service	1,332,974	1,313,015
Nonelectric Operations	394,456	362,088
Construction Work in Progress	43,057	23,363
Total Gross Plant	1,770,487	1,698,466
Less Accumulated Depreciation and Amortization	661,836	599,839
Net Plant	1,108,651	1,098,627
Total	$ 1,770,555	$ 1,754,678

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheets, December 31

(in thousands, except share data)	2010	2009
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$ 79,490	$ 7,585
Current Maturities of Long-Term Debt	604	59,053
Accounts Payable	123,095	83,724
Accrued Salaries and Wages	21,690	21,057
Accrued Taxes	12,174	11,304
Derivative Liabilities	17,991	14,681
Other Accrued Liabilities	9,546	9,638
Total Current Liabilities	264,590	207,042
Pensions Benefit Liability	73,538	95,039
Other Postretirement Benefits Liability	42,372	37,712
Other Noncurrent Liabilities	21,043	22,697
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	173,761	155,306
Deferred Tax Credits	44,945	47,660
Regulatory Liabilities	66,416	64,274
Other	556	562
Total Deferred Credits	285,678	267,802
Capitalization (page 58)		
Long-Term Debt, Net of Current Maturities	435,446	436,170
Class B Stock Options of Subsidiary	525	1,220
Cumulative Preferred Shares Authorized 1,500,000 Shares Without Par Value; Outstanding 2010 and 2009—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, 2010—36,002,739 Shares; 2009—35,812,280 Shares	180,014	179,061
Premium on Common Shares	251,919	250,398
Retained Earnings	198,443	243,352
Accumulated Other Comprehensive Income (Loss)	1,487	(1,315)
Total Common Equity	631,863	671,496
Total Capitalization	1,083,334	1,124,386
Total	$ 1,770,555	$ 1,754,678

See accompanying notes to consolidated financial statements.

Consolidated Statements of Common Shareholders' Equity and Comprehensive Income

(in thousands, except common shares outstanding)	Common Shares Outstanding	Par Value, Common Share	Premium on Common Shares	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Common Equity
Balance, December 31, 2007	**29,849,789**	**$ 149,249**	**$ 108,885**	**$ 263,332**	**$ 1,181**	**$ 522,647**
Common Stock Issuances, Net of Expenses	5,557,531	27,788	128,818			156,606
Common Stock Retirements	(22,700)	(114)	(642)			(756)
Comprehensive Income:						
Net Income				35,125		35,125
Unrealized Loss on Marketable Equity Securities (net-of-tax)					(40)	(40)
Foreign Currency Exchange Translation Loss (net-of-tax)					(2,784)	(2,784)
SFAS No. 158 Items (net-of-tax):						
Amortization of Unrecognized Postretirement Benefit Costs					153	153
Actuarial Losses and Regulatory Allocations Adjustments					(1,510)	(1,510)
Total Comprehensive Income						30,944
Tax Benefit for Exercise of Stock Options			1,777			1,777
Stock Incentive Plan Performance Award Accrual			3,093			3,093
Vesting of Restricted Stock Granted to Employees			165			165
Premium on Purchase of Stock for Employee Purchase Plan			(365)			(365)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(37,357)		(37,357)
Balance, December 31, 2008	**35,384,620**	**$ 176,923**	**$ 241,731**	**$ 260,364**	**$ (3,000)(a)**	**$ 676,018**
Common Stock Issuances, Net of Expenses	437,843	2,189	6,243			8,432
Common Stock Retirements	(10,183)	(51)	(178)			(229)
Comprehensive Income:						
Net Income				26,031		26,031
Unrealized Gain on Marketable Equity Securities (net-of-tax)					74	74
Foreign Currency Exchange Translation Gain (net-of-tax)					1,965	1,965
SFAS No. 158 Items (net-of-tax):						
Amortization of Unrecognized Postretirement Benefit Costs					357	357
Actuarial Losses and Regulatory Allocations Adjustments					(711)	(711)
Total Comprehensive Income						27,716
Tax Benefit for Exercise of Stock Options			(23)			(23)
Stock Incentive Plan Performance Award Accrual			2,592			2,592
Vesting of Restricted Stock Granted to Employees			52			52
Premium on Purchase of Stock for Employee Purchase Plan			(19)			(19)
Cumulative Preferred Dividends				(736)		(736)
Common Dividends				(42,307)		(42,307)
Balance, December 31, 2009	**35,812,280**	**$ 179,061**	**$ 250,398**	**$ 243,352**	**$ (1,315)(a)**	**$ 671,496**
Common Stock Issuances, Net of Expenses	208,333	1,042	2,054			3,096
Common Stock Retirements	(17,874)	(89)	(312)			(401)
Comprehensive Income:						
Net Loss				(1,344)		(1,344)
Unrealized Gain on Marketable Equity Securities (net-of-tax)					30	30
Foreign Currency Exchange Translation Gain (net-of-tax)					1,320	1,320
SFAS No. 158 Items (net-of-tax):						
Amortization of Unrecognized Postretirement Benefit Costs					409	409
Actuarial Gains and Regulatory Allocations Adjustments					1,043	1,043
Total Comprehensive Income						1,458
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**

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

		Before Tax	Tax Effect	Net-of-Tax
	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (6,125)	$ 2,450	$ (3,675)
2008	Foreign Currency Exchange Translation	1,155	(462)	693
	Unrealized Loss on Marketable Equity Securities	(30)	12	(18)
	Net Accumulated Other Comprehensive Loss	$ (5,000)	$ 2,000	$ (3,000)
	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (6,715)	$ 2,686	$ (4,029)
2009	Foreign Currency Exchange Translation	4,430	(1,772)	2,658
	Unrealized Gain on Marketable Equity Securities	94	(38)	56
	Net Accumulated Other Comprehensive Loss	$ (2,191)	$ 876	$ (1,315)
	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (4,296)	$ 1,718	$ (2,578)
2010	Foreign Currency Exchange Translation	5,765	(1,787)	3,978
	Unrealized Gain on Marketable Equity Securities	145	(58)	87
	Net Accumulated Other Comprehensive Income	$ 1,614	$ (127)	$ 1,487

See accompanying notes to consolidated financial statements.

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

(in thousands)	2010	2009	2008
Cash Flows from Operating Activities			
Net Income (Loss)	$ (1,344)	$ 26,031	$ 35,125
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	80,696	73,608	65,060
Asset Impairment Charge	19,740	—	—
Deferred Tax Valuation Adjustments and Tax Rate Reduction	8,300	—	—
Deferred Tax Credits	(2,715)	(2,331)	(1,692)
Deferred Income Taxes	8,601	44,792	40,665
Change in Deferred Debits and Other Assets	68	(18,527)	(41,851)
Discretionary Contribution to Pension Plan	(20,000)	(4,000)	(2,000)
Change in Noncurrent Liabilities and Deferred Credits	3,635	24,895	40,918
Allowance for Equity (Other) Funds Used During Construction	(4)	(3,180)	(2,786)
Change in Derivatives Net of Regulatory Deferral	208	(1,442)	1,044
Stock Compensation Expense—Equity Awards	2,923	3,563	3,850
Other—Net	(114)	1,489	298
Cash Provided by (Used for) Current Assets and Current Liabilities:			
Change in Receivables	(48,636)	43,822	19,522
Change in Inventories	(8,022)	16,344	(743)
Change in Other Current Assets	(13,979)	13,146	(12,362)
Change in Payables and Other Current Liabilities	31,534	(34,490)	(8,572)
Change in Interest Payable and Income Taxes Receivable/Payable	44,126	(20,970)	(25,155)
Net Cash Provided by Operating Activities	105,017	162,750	111,321
Cash Flows from Investing Activities			
Capital Expenditures	(85,589)	(177,125)	(265,888)
2009 American Recovery and Reinvestment Act Grant—Luverne Wind Farm	—	30,182	—
Proceeds from Disposal of Noncurrent Assets	3,065	4,909	8,174
Acquisitions—Net of Cash Acquired	—	—	(41,674)
Net (Increase) Decrease in Other Investments	(2,643)	(5,706)	4
Net Cash Used in Investing Activities	(85,167)	(147,740)	(299,384)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	9,865	—	—
Net Short-Term Borrowings (Repayments)	71,905	(127,329)	39,914
Proceeds from Issuance of Common Stock	549	7,420	162,978
Proceeds from Issuance of Class B Stock of Subsidiary	153	—	—
Common Stock Issuance Expenses	(142)	(23)	(6,418)
Payments for Retirement of Common Stock	(401)	(229)	(91)
Payments for Retirement of Class B Stock and Options of Subsidiary	(1,012)	—	—
Proceeds from Issuance of Long-Term Debt	95	175,000	1,240
Short-Term and Long-Term Debt Issuance Expenses	(1,699)	(5,526)	(1,252)
Payments for Retirement of Long-Term Debt	(59,331)	(23,356)	(3,639)
Dividends Paid and Other Distributions	(43,698)	(43,043)	(38,093)
Net Cash (Used in) Provided by Financing Activities	(23,716)	(17,086)	154,639
Effect of Foreign Exchange Rate Fluctuations on Cash	(566)	(1,057)	1,165
Net Change in Cash and Cash Equivalents	(4,432)	(3,133)	(32,259)
Cash and Cash Equivalents at Beginning of Year	4,432	7,565	39,824
Cash and Cash Equivalents at End of Year	$ —	$ 4,432	$ 7,565

See accompanying notes to consolidated financial statements.

Consolidated Statements of Capitalization, December 31

(in thousands, except share data)		2010	2009
Short-Term Debt			
Otter Tail Corporation Credit Agreement		$ 54,176	$ 6,000
OTP Credit Agreement		25,314	1,585
Total Short-Term Debt		$ 79,490	$ 7,585
Long-Term Debt			
Obligations of Otter Tail Corporation			
9.000% Notes, due December 15, 2016		$ 100,000	$ 100,000
Senior Unsecured Note 8.89%, due November 30, 2017		50,000	50,000
Total—Otter Tail Corporation		150,000	150,000
Obligations of Otter Tail Power Company			
Term Loan, Variable 3.73% at December 31, 2009, due May 20, 2011 (early retired on January 4, 2010)		—	58,000
Senior Unsecured Notes 6.63%, due December 1, 2011		90,000	90,000
Pollution Control Refunding Revenue Bonds, Variable, 2.50% at December 31, 2010, due December 1, 2012		10,400	10,400
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017		33,000	33,000
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017		5,100	5,125
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022		30,000	30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022		20,215	20,400
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		280,715	338,925
Obligations of Varistar Corporation—Various up to 13.31% at December 31, 2010		5,712	6,684
Total		436,427	495,609
Less:			
Current Maturities—Otter Tail Power Company		—	58,000
Current Maturities—Varistar Corporation		604	1,053
Unamortized Debt Discount—Otter Tail Corporation		5	6
Unamortized Debt Discount—Varistar Corporation		372	380
Total Long-Term Debt		435,446	436,170
Class B Stock Options of Subsidiary		525	1,220
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, 2010		
$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	$101.0125	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		631,863	671,496
Total Capitalization		$ 1,083,334	$ 1,124,386

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 AND 2008

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

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

Regulation and ASC 980

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

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

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $76,000 in 2010, $1,036,000 in 2009 and $1,692,000 in 2008. 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 3.01% in 2010, 2.90% in 2009 and 2.81% in 2008. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting, and are depreciated on a straight-line basis over the assets' estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. The amount of interest capitalized on nonelectric plant was $0 in 2010, $200,000 in 2009 and $465,000 in 2008. 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, 2010 and 2009 consolidated balance sheets:

(in thousands)	2010	2009
Big Stone Plant:		
Electric Plant in Service	$ 135,982	$ 135,500
Construction Work in Progress	3,163	380
Accumulated Depreciation	(81,264)	(78,306)
Net Plant	$ 57,881	$ 57,574
Coyote Station:		
Electric Plant in Service	$ 155,813	$ 155,417
Construction Work in Progress	178	34
Accumulated Depreciation	(90,005)	(87,269)
Net Plant	$ 65,986	$ 68,182

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

Recoverability of Long-Lived Assets

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

Income Taxes

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

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

Revenue Recognition

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as OTP's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with ASC 815-10-45-9. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

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

Customer electricity use is metered and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment (FCA), under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is accrued for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the FCA, for conservation program incentives and bonuses earned but not yet billed and for renewable resource 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, *Derivatives and Hedging*, OTP's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. See note 5 for further discussion.

Wind Energy operating revenues are recorded on a percentage-of-completion method for production of wind towers, similar to construction-type contracts, and transportation revenues are recorded when services are rendered or goods are delivered.

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

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

Plastics operating revenues are recorded when the product is shipped.

Health Services operating revenues on major equipment and installation contracts are recorded when the equipment is delivered or when installation is completed and accepted. Amounts received in advance under customer service contracts are deferred and recognized on a straight-line basis over the contract period. Revenues generated in the imaging operations are recorded on a fee-per-scan basis when the scan is performed.

Food Ingredient Processing revenues are recorded when product is shipped.

Some of the operating businesses in the Company's Wind Energy, Manufacturing and Construction segments enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company's consolidated revenues recorded under the percentage-of-completion method were 25.9% in 2010, 27.6% in 2009 and 33.5% in 2008. The method used to determine the progress of completion is based on the ratio of labor hours incurred to total estimated labor hours at the Company's wind tower manufacturer and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2010	December 31, 2009
Costs Incurred on Uncompleted Contracts	$ 460,125	$ 400,577
Less Billings to Date	(430,471)	(400,711)
Plus Estimated Earnings Recognized	31,231	59,202
	$ 60,885	$ 59,068

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

(in thousands)	December 31, 2010	December 31, 2009
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 67,352	$ 61,835
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(6,467)	(2,767)
	$ 60,885	$ 59,068

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI), the Company's wind tower manufacturer, were $58,990,000 as of December 31, 2010 and $54,977,000 as of December 31, 2009. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

Retainage

Accounts Receivable include amounts billed by the Company's subsidiaries under long-term contracts that have been retained by customers pending project completion of $11,848,000 on December 31, 2010 and $9,215,000 on December 31, 2009.

Sales of Receivables

DMI is a party to a $40 million receivables purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. The agreement, originally scheduled to expire in March 2011, was extended for one year by DMI in February 2011. The discount rate for the one-year extension has been increased to 3-month LIBOR plus 4%. Accounts receivable sold totaled $62,651,000 in 2010 and $133,900,000 in 2009. Discounts and commissions and fees charged to operating expenses in the consolidated statements of income were $208,000 in 2010 and $430,000 in 2009. In compliance with guidance under ASC 860-20, *Sales of Financial Assets*, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

Marketing and Sales Incentive Costs

ShoreMaster, Inc. (ShoreMaster), the Company's waterfront equipment manufacturer, provides dealer floor plan financing assistance for certain dealer purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer's order. ShoreMaster recognizes the estimated cost of projected interest payments related to each financed sale as a liability and a reduction of revenue at the time of sale, based on historical experience of the average length of time floor plan debt is outstanding, in accordance with guidance under ASC 605-50, *Customer Payments and Incentives*. The liability is reduced when interest is paid. To the extent current experience differs from previous estimates the accrued liability for financing assistance costs is adjusted accordingly. Financing assistance costs charged to revenue were $97,000 in 2010, $131,000 in 2009 and $500,000 in 2008.

Foreign Currency Translation

The functional currency for the operations of the Canadian subsidiary of Idaho Pacific Holdings, Inc. (IPH) is the Canadian dollar (CAD). This subsidiary realizes foreign currency transaction gains or losses on settlement of receivables related to its sales, which are mostly in U.S. dollars (USD), and on exchanging U.S. currency for Canadian currency for its Canadian operations. This subsidiary recorded foreign currency transaction losses of $260,000 USD in 2010, $337,000 USD in 2009 and $60,000 USD in 2008 as a result of fluctuations in the value of the Canadian dollar relative to the U.S. dollar during those years. The translation of CAD to USD is performed for balance sheet accounts using exchange rates in effect at the balance sheet dates—except for the common equity accounts which are at historical rates—and for revenue and expense accounts using a weighted average exchange during the year. Gains or losses resulting from the translation are included in Accumulated Other Comprehensive Income (Loss) in the equity section of the Company's consolidated balance sheet.

The functional currency for the Canadian subsidiary of DMI is the U.S. dollar. There are no foreign currency translation gains or losses related to this entity. However, this subsidiary may realize foreign currency transaction gains or losses on settlement of liabilities related to goods or services purchased in CAD. Foreign currency transaction losses related to balance sheet adjustments of CAD liabilities to USD equivalents and realized losses on settlement of those liabilities were $740,000 USD in 2010 as a result of an increase in the value of the Canadian dollar relative to the U.S. dollar in 2010. Foreign currency transaction gains related to balance sheet adjustments of CAD liabilities to USD equivalents and realized gains on settlement of those liabilities were $77,000 USD in 2009 and $399,000 USD in 2008 as a result of decreases in the value of the Canadian dollar relative to the U.S. dollar in 2009 and 2008.

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, accrued renewable resource and transmission rider revenues, accrued conservation improvement program incentives and bonuses, valuations of forward energy contracts, service contract maintenance costs, percentage-of-completion 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.

Supplemental Disclosures of Cash Flow Information

(in thousands)	2010	2009	2008
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$ 954	$ (3,832)	$ (22,729)
Noncash Investing and Financing Transactions:			
Capital Leases	—	—	$ 2,084
Cash Paid During the Year for:			
Interest (net of amount capitalized)	$ 33,094	$ 23,563	$ 25,032
Income Tax (Refunds) Payments	$ (54,346)	$ (27,412)	$ 1,356

Investments

The following table provides a breakdown of the Company's investments at December 31, 2010 and 2009:

(in thousands)	December 31, 2010	December 31, 2009
Cost Method:		
Economic Development Loan Pools	$ 387	$ 482
Other	244	334
Equity Method:		
Affordable Housing and Other Partnerships	610	1,025
Marketable Securities Classified as Available-for-Sale	8,467	8,048
Total Investments	$ 9,708	$ 9,889

The Company has investments in eleven limited partnerships that invest in tax-credit-qualifying affordable-housing projects that provided tax credits of $4,000 in 2010, $25,000 in 2009 and $55,000 in 2008. The Company owns a majority interest in eight of the eleven limited partnerships with a total investment of $593,000. ASC 810, *Consolidation*, requires full consolidation of the majority-owned partnerships. However, the Company includes these entities on its consolidated financial statements on a declining balance basis due to immateriality and uncertainty regarding residual values. Consolidating these entities would have represented 0.4% of total assets, 0.1% of total revenues and (1.2%) of operating income for the Company as of, and for the year ended, December 31, 2010 and would have an insignificant impact on the Company's 2010 consolidated net loss.

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their market values on December 31, 2010. 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 and requires enhanced disclosures about assets and liabilities measured at fair value. ASC 820-10-35 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

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

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

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

The following table presents, for each of these hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2010 and 2009:

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

2009 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments for Nonqualified			
Retirement Savings Retirement Plan:			
Money Market and Mutual Funds and Cash	$ 731	$ —	
Forward Energy Contracts		8,321	
Regulatory Asset—Deferred Mark-to-Market			
Losses on Forward Energy Contracts (1)		7,614	
Investments of Captive Insurance Company:			
Corporate Debt Securities	7,795		
U.S. Government Debt Securities	253		
Total Assets	$ 8,779	$ 15,935	
Liabilities:			
Forward Energy Contracts	$ —	$ 14,681	
Regulatory Liability—Deferred Mark-to-Market			
Gains on Forward Energy Contracts (1)		224	
Total Liabilities	$ —	$ 14,905	

(1) Table has been corrected to include regulatory assets and liabilities related to deferred losses and gains on forward energy contracts measured at fair value. These assets and liabilities were reported at fair value in note 5 to consolidated financial statements in 2009.

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

Inventories

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

(in thousands)	**December 31, 2010**	December 31, 2009
Finished Goods	$ 43,426	$ 42,784
Work in Process	7,171	3,824
Raw Material, Fuel and Supplies	44,419	39,907
Total Inventories	$ 95,016	$ 86,515

Goodwill and Other Intangible Assets

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

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

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

(in thousands)	
Goodwill	$ 12,259
Brand/Trade Name	4,869
Other Intangible Assets	507
Long-Lived Assets	2,105
Total Asset Impairment Charges	$ 19,740

Goodwill in the Health Services segment was reduced by $213,000 in the second quarter of 2010 as a result of the sale of certain imaging assets and routes.

In December 2010, an assessment of the fair value of the investment of Otter Tail Energy Services Company (OTESCO) in a mechanical and HVAC contracting firm indicated that the carrying value of the entity was in excess of its fair value. The fair value determination indicated the goodwill associated with this entity was 100% impaired. A reduction of goodwill and impairment charge of $240,000 was recorded in December 2010 as a result of the fair value determination.

The following table summarizes changes to goodwill by business segment during 2010:

(in thousands)	Balance December 31, 2009	Adjustment to Goodwill for Assets Sold in 2010	Balance December 31, 2010	Impairments	Balance (net of impairments) December 31, 2010
Electric	$ 240	$ —	$ 240	$ (240)	$ —
Wind Energy	6,959	—	6,959	—	6,959
Manufacturing	24,445	—	24,445	(12,259)	12,186
Construction	7,630	—	7,630	—	7,630
Plastics	19,302	—	19,302	—	19,302
Health Services	23,878	(213)	23,665	—	23,665
Food Ingredient Processing	24,324	—	24,324	—	24,324
Total	$ 106,778	$ (213)	$ 106,565	$ (12,499)	$ 94,066

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

2010 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Customer Relationships	$26,998	$ 4,954	$ 22,044	15–25 years
Covenants Not to Compete	1,704	1,676	28	3–5 years
Other Intangible Assets Including Contracts	930	891	39	5–30 years
Total	$29,632	$ 7,521	$ 22,111	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 5,021	$ —	$ 5,021	
2009 *(in thousands)*				
Amortized Intangible Assets:				
Customer Relationships	$26,956	$ 3,696	$ 23,260	15–25 years
Covenants Not to Compete	2,190	2,047	143	3–5 years
Other Intangible Assets Including Contracts	2,358	1,757	601	5–30 years
Total	$31,504	$ 7,500	$ 24,004	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,883	$ —	$ 9,883	

The amortization expense for these intangible assets was $1,420,000 for 2010, $1,656,000 for 2009 and $1,464,000 for 2008. The estimated annual amortization expense for these intangible assets for the next five years is $1,314,000 for 2011, $1,335,000 for 2012, $1,331,000 for 2013, $1,331,000 for 2014 and $1,331,000 for 2015.

Reclassifications

In order to provide a consistent representation of regulatory assets on the face of the Company's consolidated balance sheets and in the notes to its consolidated financial statements, deferred amounts related to premiums paid on the reacquisition of debt related to regulated operations as of December 31, 2009 totaling $3,051,000 were reclassified from Unamortized Debt Expense and Reacquisition Premiums to Regulatory Assets and Other Deferred Debits in September 2010, and the line item title on the face of the Company's consolidated balance sheet was changed from Unamortized Debt Expense and Reacquisition Premiums to Unamortized Debt Expense. The deferral of gains and losses incurred on the reacquisition of debt is an accounting treatment prescribed for regulated utilities under regulatory accounting rules and, as such, deferred losses on the reacquisition of debt are generally classified as regulatory assets. The Company has historically reported the unamortized balance of losses on the reacquisition of debt related to its regulated electric utility operations as a regulatory asset in the notes to its consolidated financial statements.

New Accounting Standards

Consolidation of Variable Interest Entities—In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance affects various elements of consolidation, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. These updates to the Accounting Standards Codification are effective for interim and annual periods beginning after November 15, 2009. The Company implemented the guidance on January 1, 2010 and the implementation did not have a material impact on its consolidated financial statements.

Accounting Standards Update (ASU) No. 2010-06 Fair Value Measurements and Disclosures (Topic 820)—Improving Disclosures about Fair Value Measurements, issued by the FASB in January 2010, updates ASC 820 to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for fair value measurements, transfers between levels of the fair value hierarchy, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to ASC 820 contained in ASU No. 2010-06 were effective for interim and annual periods beginning after December 15, 2009, except for requirements related to gross presentation of certain changes in Level 3 fair value measurements, which are effective for interim and annual periods beginning after December 15, 2010. The implementation of applicable guidance from ASU No. 2010-06 on January 1, 2010 did not have a material impact on the Company's consolidated financial statements, but did require additional fair value disclosures in footnotes to interim financial statements, similar to disclosures required with year-end financial statements.

2. BUSINESS COMBINATIONS, DISPOSITIONS AND SEGMENT INFORMATION

There were no acquisitions or dispositions of businesses in 2010 and 2009.

On May 1, 2008 BTD Manufacturing, Inc. (BTD), acquired the assets of Miller Welding & Ironworks, Inc. (Miller Welding) of Washington, Illinois for $41.7 million in cash. Miller Welding, a custom job shop fabricator and finisher, recorded $26 million in revenue in 2007. Miller Welding 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. This acquisition will provide opportunities for growth in new and existing markets for both BTD and Miller Welding, and complementing production capabilities will expand the scope and capacity of services offered by both companies.

Below is condensed balance sheet information, at the date of the business combination, disclosing the allocation of the purchase price assigned to each major asset and liability category of Miller Welding:

(in thousands)	
Assets	
Current Assets	$ 8,855
Goodwill	7,986
Other Intangible Assets	16,600
Fixed Assets	8,994
Total Assets	$ 42,435
Liabilities	
Current Liabilities	$ 761
Noncurrent Liabilities	—
Total Liabilities	$ 761
Cash Paid	$ 41,674

Other Intangible Assets related to the Miller Welding acquisition include $16,100,000 for Customer Relationships being amortized over 20 years, $400,000 for a Nonamortizable Trade Name and a $100,000 Covenant Not to Compete being amortized over three years. The acquisition described above was accounted for using the purchase method of accounting. Disclosure of pro forma information related to the results of operations of Miller Welding for the twelve months ended December 31, 2008 is not required due to immateriality.

Segment Information

The accounting policies of the segments are described under note 1—Summary of Significant Accounting Policies. Effective October 1, 2010, the Company realigned its business structure and defined its operating segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision makers. Prior to the realignment, the businesses of the Company were classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. All information in the Company's consolidated financial statements for the years ended December 31, 2010, 2009 and 2008, including footnote information, has been revised to reflect the realignment of the Company's business segments. The Company's seven reporting segments are as follows:

ELECTRIC	WIND ENERGY	MANUFACTURING	CONSTRUCTION	PLASTICS	HEALTH SERVICES	FOOD INGREDIENT PROCESSING
Otter Tail Power Company	DMI Industries, Inc.	BTD Manufacturing, Inc.	Foley Company	Northern Pipe Products, Inc.	DMS Health Technologies, Inc.	Idaho Pacific Holdings, Inc.
Otter Tail Energy Services Company	E.W. Wylie Corporation	ShoreMaster, Inc.	Aevenia, Inc.	Vinyltech Corporation		
		T.O. Plastics, Inc.				

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 now includes OTESCO, which provides technical and engineering services and energy efficient lighting primarily in North Dakota and Minnesota. OTESCO's activities were included in Other Business Operations prior to the realignment of the Company's business segments.

Wind Energy consists of two businesses: a steel fabrication company primarily involved in the production of wind towers sold in the United States and Canada, with manufacturing facilities in North Dakota, Oklahoma and Ontario, Canada, and a trucking company headquartered in West Fargo, North Dakota, specializing in flatbed and heavy-haul services and operating in 49 states and six Canadian provinces. Prior to the realignment of the Company's business segments, the wind tower production company was included in Manufacturing and the trucking company was included in Other Business Operations.

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

Construction consists of businesses involved in residential, commercial and industrial electric contracting and construction of fiber optic and electric distribution systems, water, wastewater and HVAC systems primarily in the central United States. Construction operations were included in Other Business Operations prior to the realignment of the Company's business segments.

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

Health Services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging equipment and technical staff to various medical institutions located throughout the United States.

Food Ingredient Processing consists of IPH, which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries. Approximately 18%, 16% and 25% of IPH's sales in 2010, 2009 and 2008, respectively, were to customers outside 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).

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

The Company had no single external customer that accounted for 10% or more of the Company's consolidated revenues in 2010. In 2009, the Company had one customer within the Wind Energy segment that accounted for 13.6% of the Company's consolidated revenues. Substantially all of the Company's long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

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

	2010	2009	2008
United States of America	97.4%	97.8%	97.3%
Canada	1.4%	0.8%	1.1%
All Other Countries	1.2%	1.4%	1.6%

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for 2010, 2009 and 2008 is presented in the following table:

(in thousands)	2010	2009	2008
Operating Revenue			
Electric	$ 340,313	$ 314,666	$ 340,075
Wind Energy	197,746	192,923	290,832
Manufacturing	178,690	164,186	222,482
Construction	134,222	103,831	157,053
Plastics	96,945	80,208	116,452
Health Services	100,301	110,006	122,520
Food Ingredient Processing	77,412	79,098	65,367
Corporate and Intersegment Eliminations	(6,545)	(5,406)	(3,584)
Total	$1,119,084	$1,039,512	$1,311,197
Depreciation and Amortization			
Electric	$ 40,241	$ 36,946	$ 31,755
Wind Energy	11,087	10,316	8,254
Manufacturing	12,848	12,754	11,359
Construction	2,023	2,010	1,877
Plastics	3,430	2,945	3,050
Health Services	5,840	3,907	4,133
Food Ingredient Processing	4,703	4,333	4,094
Corporate	524	397	538
Total	$ 80,696	$ 73,608	$ 65,060
Interest Charges			
Electric	$ 20,949	$ 19,465	$ 12,954
Wind Energy	6,136	3,025	4,687
Manufacturing	5,117	2,982	4,437
Construction	671	175	651
Plastics	1,560	811	1,156
Health Services	1,289	448	714
Food Ingredient Processing	111	36	109
Corporate and Intersegment Eliminations	1,199	1,572	2,250
Total	$ 37,032	$ 28,514	$ 26,958
Income Before Income Taxes			
Electric	$ 44,505	$ 34,063	$ 45,444
Wind Energy	(21,073)	1,181	5,311
Manufacturing	(19,389)	(10,035)	2,669
Construction	(1,115)	1,991	9,122
Plastics	4,007	(126)	3,114
Health Services	549	(3,210)	342
Food Ingredient Processing	11,714	11,817	2,655
Corporate	(16,591)	(14,255)	(18,495)
Total	$ 2,607	$ 21,426	$ 50,162
Earnings (Loss) Available for Common Shares			
Electric	$ 34,557	$ 33,310	$ 32,092
Wind Energy	(21,228)	777	3,294
Manufacturing	(14,765)	(5,512)	2,153
Construction	(646)	1,220	5,507
Plastics	2,515	(59)	1,880
Health Services	180	(2,096)	85
Food Ingredient Processing	7,998	7,407	1,681
Corporate	(10,788)	(9,752)	(12,303)
Total	$ (2,177)	$ 25,295	$ 34,389
Capital Expenditures			
Electric	$ 43,121	$ 146,128	$ 197,673
Wind Energy	3,733	11,964	37,667
Manufacturing	6,586	7,944	10,630
Construction	5,490	2,131	3,110
Plastics	2,671	4,269	8,883
Health Services	21,922	3,439	4,039
Food Ingredient Processing	1,243	686	3,645
Corporate	823	564	241
Total	$ 85,589	$ 177,125	$ 265,888
Identifiable Assets			
Electric	$1,106,261	$1,121,241	$ 993,441
Wind Energy	175,852	160,540	194,175
Manufacturing	144,272	162,512	182,913
Construction	60,978	41,455	49,686
Plastics	73,508	70,380	78,054
Health Services	75,898	58,164	61,086
Food Ingredient Processing	90,684	88,478	88,813
Corporate	43,102	51,908	44,419
Total	$1,770,555	$1,754,678	$1,692,587

Revised Segments Information by Quarter (not audited)

The following table provides segment information for the Company's revised segments, 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)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Operating Revenue								
Electric	**$ 91,090**	$ 88,554	**$ 76,288**	$ 70,676	**$ 88,765**	$ 73,561	**$ 84,170**	$ 81,875
Wind Energy	**49,398**	56,747	**47,631**	42,583	**42,435**	48,698	**58,282**	44,895
Manufacturing	**38,031**	46,380	**49,507**	42,440	**43,342**	36,812	**47,810**	38,554
Construction	**17,774**	24,933	**30,149**	21,575	**36,885**	26,729	**49,414**	30,594
Plastics	**23,087**	13,530	**26,739**	22,183	**26,736**	27,353	**20,383**	17,142
Health Services	**25,171**	28,167	**23,645**	28,192	**24,300**	27,053	**27,185**	26,594
Food Ingredient Processing	**18,915**	20,086	**18,255**	20,581	**19,478**	18,691	**20,764**	19,740
Corporate and Intersegment Eliminations	**(1,280)**	(1,158)	**(2,019)**	(1,373)	**(1,274)**	(1,457)	**(1,972)**	(1,418)
Total	**$ 262,186**	$ 277,239	**$ 270,195**	$ 246,857	**$ 280,667**	$ 257,440	**$ 306,036**	$ 257,976
Interest Charges								
Electric	**$ 5,270**	$ 4,023	**$ 5,349**	$ 4,277	**$ 5,172**	$ 5,394	**$ 5,158**	$ 5,771
Wind Energy	**1,321**	639	**1,549**	785	**1,641**	722	**1,625**	879
Manufacturing	**1,247**	714	**1,294**	714	**1,298**	689	**1,278**	865
Construction	**118**	34	**155**	41	**190**	38	**208**	62
Plastics	**363**	200	**428**	199	**403**	181	**366**	231
Health Services	**245**	96	**280**	100	**377**	108	**387**	144
Food Ingredient Processing	**37**	10	**28**	10	**35**	9	**11**	7
Corporate and Intersegment Eliminations	**429**	554	**322**	526	**178**	217	**270**	275
Total	**$ 9,030**	$ 6,270	**$ 9,405**	$ 6,652	**$ 9,294**	$ 7,358	**$ 9,303**	$ 8,234
Income Tax Expense (Benefit)								
Electric	**$ 4,834**	$ 1,695	**$ (529)**	$ (904)	**$ 4,257**	$ 1,337	**$ 1,386**	$ (1,743)
Wind Energy	**(7)**	292	**(1,498)**	67	**(3,496)**	802	**5,156**	(757)
Manufacturing	**(618)**	(1,515)	**(3,833)**	(518)	**(350)**	(732)	**177**	(1,758)
Construction	**(1,002)**	289	**(305)**	(629)	**435**	107	**403**	1,004
Plastics	**494**	(1,647)	**141**	198	**238**	896	**619**	486
Health Services	**(432)**	(13)	**55**	(63)	**311**	(395)	**435**	(643)
Food Ingredient Processing	**727**	725	**1,110**	1,613	**1,193**	1,068	**686**	1,004
Corporate	**(1,616)**	(1,208)	**(1,683)**	(1,616)	**(1,970)**	(1,928)	**(1,367)**	(119)
Total	**$ 2,380**	$ (1,382)	**$ (6,542)**	$ (1,852)	**$ 618**	$ 1,155	**$ 7,495**	$ (2,526)
Earnings (Loss) Available for Common Shares								
Electric	**$ 7,491**	$ 8,218	**$ 4,432**	$ 4,071	**$ 12,265**	$ 9,422	**$ 10,369**	$ 11,599
Wind Energy	**33**	428	**(2,639)**	73	**(7,072)**	1,187	**(11,550)**	(911)
Manufacturing	**(735)**	(2,150)	**(15,116)**	(609)	**(383)**	(1,341)	**1,469**	(1,412)
Construction	**(1,489)**	431	**(494)**	(947)	**646**	154	**691**	1,582
Plastics	**781**	(2,458)	**232**	291	**367**	1,298	**1,135**	810
Health Services	**(691)**	(73)	**35**	(153)	**421**	(649)	**415**	(1,221)
Food Ingredient Processing	**1,404**	1,447	**1,882**	2,325	**1,991**	1,772	**2,721**	1,863
Corporate	**(2,261)**	(1,639)	**(2,829)**	(2,504)	**(2,321)**	(1,435)	**(3,377)**	(4,174)
Total	**$ 4,533**	$ 4,204	**$ (14,497)**	$ 2,547	**$ 5,914**	$ 10,408	**$ 1,873**	$ 8,136
Identifiable Assets								
Electric	**$ 1,127,045**	$ 992,563	**$ 1,082,517**	$ 1,060,113	**$ 1,096,823**	$ 1,101,242	**$ 1,106,261**	$ 1,121,241
Wind Energy	**190,888**	173,746	**180,763**	159,042	**175,198**	146,767	**175,852**	160,540
Manufacturing	**167,095**	184,212	**147,970**	171,917	**145,126**	169,344	**144,272**	162,512
Construction	**47,373**	48,792	**49,609**	44,495	**58,356**	46,050	**60,978**	41,455
Plastics	**79,591**	75,896	**78,799**	74,239	**76,289**	72,298	**73,508**	70,380
Health Services	**63,845**	58,675	**67,205**	59,843	**69,804**	58,526	**75,898**	58,164
Food Ingredient Processing	**91,412**	87,459	**91,474**	87,426	**91,108**	89,117	**90,684**	88,478
Corporate	**48,712**	49,600	**46,902**	53,663	**47,998**	54,659	**43,102**	51,908
Total	**$ 1,815,961**	$ 1,670,943	**$ 1,745,239**	$ 1,710,738	**$ 1,760,702**	$ 1,738,003	**$ 1,770,555**	$ 1,754,678

3. RATE AND REGULATORY MATTERS

Minnesota

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

2010 General Rate Case Filing—OTP filed a general rate case on April 2, 2010 requesting an 8.01% increase with a 3.8% interim rate request. On May 27, 2010, the MPUC issued an order accepting the filing, suspending rates and setting interim rates. The MPUC approved a 3.8% interim rate increase to be effective with customer usage on and after June 1, 2010. OTP expects oral arguments before the MPUC and deliberations to take place late March 2011 and the MPUC to issue an order by April 25, 2011. Interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the request. If final rates are lower than interim rates, OTP will refund Minnesota customers the difference, with interest.

Renewable Energy Standards, Conservation, Renewable Resource Riders—Minnesota has a renewable energy standard that requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP has sufficient renewable energy resources available and in service to comply with the required 2016 level of the Minnesota renewable energy standard. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

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

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

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

On January 12, 2010, the MPUC issued an order finding OTP's Luverne Wind Farm project eligible for cost recovery through the MNRRA. The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010. The MPUC approved OTP's petition for a 2010 MNRRA in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the MNRRA to $0.00684 per kwh plus $0.298 per kilowatt (kW) for the large general service class, and $0.00760 per kwh for all other customer classes. The 2010 MNRRA was established with an expected recovery of $16.2 million over the period September 1, 2010 to August 31, 2011. The 2010 MNRRA will be in effect until the MPUC sets another updated MNRRA. The MPUC is also considering in OTP's general rate case whether to move recovery of these renewable projects into OTP's base rates. OTP has recognized a regulatory asset of $6.8 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of December 31, 2010.

Transmission Cost Recovery (TCR) Rider—In addition to the Renewable Resource Cost Recovery Rider, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or otherwise deemed eligible by the MPUC. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010, OTP's TCR rider rate is reflected on Minnesota customer electric service statements at $0.00039 per kwh plus $0.035 per kW for large general service customers and $0.00007 per kwh for controlled service customers, $0.00025 per kwh for lighting customers, and $0.00057 per kwh for all other customers. As of December 31, 2010 OTP had accrued a $34,000 regulatory asset for transmission related revenues that are subject to recovery through the rider. In a request for a revenue increase under general rates filed with the MPUC on April 2, 2010, OTP requested recovery of its transmission investments currently being recovered through OTP's Minnesota TCR rider rate. The transmission investments will continue to be recovered through OTP's Minnesota TCR rider rate until the MPUC makes a decision on OTP's general rate case. OTP filed a request for an update to its Minnesota TCR rider rate on October 5, 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 request to remove from base rates the recovery of costs associated with economic development in North Dakota. OTP proposed and the NDPSC approved an Economic Development Cost Removal Rider, under which all North Dakota customers will receive a credit of $0.00025 per kwh. The monthly credit was effective with bills rendered on and after January 1, 2011.

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

In a proceeding that was combined with OTP's 2008 general rate case, the NDPSC reviewed whether to move the costs of the projects currently being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to $0.00369 for the period from December 1, 2009 until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA (which includes cost recovery for OTP's investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010. Approval for implementation of an updated NDRRA was received in the third quarter of 2010 with implementation effective September 1, 2010. This approval increased the NDRRA to $0.00473 per kwh plus $0.212 per kW for the large general service class, and $0.00551 per kwh for all other customer classes. The 2010 NDRRA was established with an expected recovery of $15.8 million over the period September 1, 2010 to March 31, 2012. The 2010 NDRRA will be in effect until the NDPSC sets another updated NDRRA.

OTP had not been deferring recognition of its renewable resource costs eligible for recovery under the NDRRA but had been charging those costs to operating expense since January 2008. After approval of the rider in May 2008, OTP accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that were eligible for recovery through the NDRRA. Terms of the approved settlement provide for the recovery of accrued but unbilled NDRRA revenues over a period of 48 months beginning in January 2010. The Company's December 31, 2010 consolidated balance sheet includes a regulatory asset of $2.4 million for revenues that are eligible for recovery through the NDRRA but have not been billed to North Dakota customers.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP requested recovery of such costs in its general rate case filed in November 2008 and was granted recovery of such costs by the NDPSC in its November 25, 2009 order. OTP anticipates filing a request for an initial North Dakota TCR rider with the NDPSC in the first quarter of 2011.

South Dakota

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

2010 General Rate Case Filing—On August 20, 2010 OTP filed a general rate case with the SDPUC requesting an overall revenue increase of approximately $2.8 million, or just under 10.0%, which includes, among other things, recovery of investments and expenses related to renewable resources. On September 28, 2010 the SDPUC suspended OTP's proposed rates for a period of 180 days to allow time to review OTP's proposal. The SDPUC ordered the assessment of a filing fee up to $125,000 to cover a portion of its expenses to review the filing. South Dakota statutes allow OTP to implement proposed rates 180 days after the date of filing a general rate case even if the SDPUC has not approved its initial 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 also 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. A hearing before the SDPUC is expected in April, 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.

Federal

Revenue Sufficiency Guarantee (RSG) Charges—Since 2006, OTP has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdrew energy from the market or engaged in financial-only, virtual sales of energy into the market, or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC's orders are on review before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). As of the date of this report OTP does not have a known liability. The Company continues to monitor the proceedings but cannot predict the outcome.

Capacity Expansion 2020 (CapX2020)

Fargo-Monticello 345 kiloVolt (kV) Project, Brookings-Southeast Twin Cities 345 kV Project and Twin Cities-LaCrosse 345 kV Project—On April 16, 2009 the MPUC approved the CONs for the three 345 kV Group 1 CapX2020 line projects (Fargo-Monticello, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse).

The route permit application for the Monticello to St. Cloud portion of the Fargo project was filed in April 2009. The MPUC approved the route permit application and issued a written order on July 12, 2010. Required permits from the Minnesota Department of Transportation, Minnesota Department of Natural Resources and the U.S. Army Corps of Engineers were received in 2010. A Transmission Capacity Exchange Agreement, allocating transmission capacity rights to owners across the Monticello to St. Cloud portion of the project, was accepted by the FERC in the third quarter of 2010.

The Minnesota route permit application for the St. Cloud to Fargo portion of the Fargo project was filed on October 1, 2009. The MPUC is expected to make a determination on the route permit application in the second quarter of 2011. Minnesota State Environmental Impact Statement (EIS) scoping meetings were held in September 2010 and public hearings were held in November 2010. On October 8, 2010, OTP submitted its application for a Certificate of Public Convenience and Necessity (CPCN) from the NDPSC for the North Dakota portion of the Fargo-Monticello 345 kV project. The NDPSC approved the CPCN in January 2011. The application for North Dakota Certificate of Corridor Compatibility was filed on December 30, 2010.

The route permit application for the Brookings project was filed in the fourth quarter of 2008. On July 15, 2010 the MPUC voted to approve most of the Brookings route permit application. On September 15, 2010 the MPUC approved a route permit for five of six project line segments, with the exception of the line segment that crosses the Minnesota River. Additional Evidentiary Hearings were held regarding the line segment crossing the Minnesota River, and the Administrative Law Judge issued a report in December 2010. The MPUC approved the final line segment for the project on February 3, 2011.

An application for a South Dakota facility route permit was filed with the SDPUC on November 22, 2010. The SDPUC conducted a public hearing in January 2011 and a South Dakota route permit is expected to be approved in the second quarter of 2011.

Bemidji-Grand Rapids 230 kV Project—OTP serves as the lead utility for the CapX2020 Bemidji-Grand Rapids 230-kV project, which has an expected in-service date of late 2012 or early 2013. The MPUC approved the CON for this project on July 9, 2009. A route permit application was filed with the MPUC in the second quarter of 2008 for the Bemidji-Grand Rapids project. On October 28, 2010 the MPUC approved the route permit application for the project. The joint state and federal EIS was published by the federal agencies on September 7, 2010, and the project's Transmission Capacity Exchange Agreement was accepted and approved by the FERC in the third quarter of 2010.

CapX2020 Request for Advance Determination of Prudence—On October 5, 2009 OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of the four Group 1 projects (Fargo-Monticello, Brookings-Southeast Twin Cities, and Bemidji-Grand Rapids). 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 issuing an advance determination of prudence 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-Southeast Twin Cities project and its associated impact on North Dakota.

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's) regional haze regulations, South Dakota has developed and submitted its implementation plan and associated implementing rules to EPA. Under the South Dakota Implementation Plan, and its implementing rules that became effective in December 2010, the Big Stone Plant must install and operate a new BART compliant air quality control system to reduce emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's implementation plan. Although studies and evaluations are continuing, the current projected project cost is estimated to be approximately $490 million (OTP's share would be $264 million). On January 14, 2011 OTP filed a petition asking the MPUC for advance determination of prudence 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. The Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

Big Stone II Project

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

In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC Advocacy Staff, OTP and the North Dakota Large Industrial Energy Group, Interveners. The order modified the settlement agreement slightly by using OTP's average 2009 Allowance for Funds Used During Construction (AFUDC) rate of 7.65%, rather than OTP's approved rate of return of 8.62% from the NDPSC rate case order of November 25, 2009 as called for by the settlement agreement, to accrue carrying charges during the period from September 1, 2009 to entry of the NDPSC order. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excludes $2,612,000 of project transmission-related costs) was determined to be $10,080,000, of which $4,064,000 represents North Dakota's jurisdictional share.

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

The portion of Big Stone II costs incurred by OTP related to transmission is $2,612,000, of which $1,053,000 represents North Dakota's jurisdictional share. OTP transferred the North Dakota share of Big Stone II transmission costs to Construction Work in Progress (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.

As of December 31, 2010 OTP had $7.9 million in incurred costs related to the project that have not been approved for recovery. OTP has deferred recognition of these costs as operating expenses pending determination of recoverability by the state regulatory commissions that approve its rates. In filings made on December 14, 2009, OTP requested from the MPUC and the SDPUC authority to reflect these costs on its books as a regulatory asset through the use of deferred accounting, pending a determination on the recoverability of the costs. OTP has 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, and thereafter requested withdrawal of its December 14, 2009 request for deferred accounting as duplicative of the issues presented in the rate case. On December 30, 2010 OTP filed a request for an extension of the Minnesota Route Permit for the Big Stone transmission facilities. The request asks to extend the deadline for filing a CON for these transmission facilities until March 17, 2013. 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.

If Minnesota or South Dakota jurisdictions eventually deny recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed unrecoverable.

4. REGULATORY ASSETS AND LIABILITIES

As a regulated entity OTP accounts for the financial effects of regulation in accordance with ASC 980, *Regulated Operations*. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation.

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheet:

(in thousands)	December 31, 2010	December 31, 2009
Regulatory Assets—Current:		
Accrued Cost-of-Energy Revenue	$ 2,387	$ 1,175
Regulatory Assets—Long Term:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 74,156	$ 78,871
Deferred Marked-to-Market Losses	12,054	7,614
Unrecovered Project Costs—Big Stone II	11,324	12,982
Minnesota Renewable Resource Rider Accrued Revenues	6,834	5,324
Deferred Conservation Improvement Program Costs & Accrued Incentives	6,655	1,908
Deferred Income Taxes	5,785	5,441
Debt Reacquisition Premiums	3,107	3,051
North Dakota Renewable Resource Rider Accrued Revenues	2,415	566
Accumulated ARO Accretion/Depreciation Adjustment	2,218	1,808
General Rate Case Recoverable Expenses	1,773	1,693
MISO Schedule 16 and 17 Deferred Administrative Costs—ND	717	1,091
South Dakota—Asset-Based Margin Sharing Shortfall	501	330
Deferred Holding Company Formation Costs	193	248
Minnesota Transmission Rider Accrued Revenues	34	420
MISO Schedule 16 and 17 Deferred Administrative Costs—MN	—	252
Plant Acquisition Costs	—	18
Total Regulatory Assets—Long Term	$ 127,766	$ 121,617
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs—Net of Salvage	$ 61,740	$ 58,937
Deferred Income Taxes	4,289	4,965
Deferred Marked-to-Market Gains	175	224
Deferred Gain on Sale of Utility Property—Minnesota Portion	128	134
South Dakota—Asset-Based Margin Sharing Excess	84	14
Total Regulatory Liabilities	$ 66,416	$ 64,274
Net Regulatory Asset Position	$ 63,737	$ 58,518

The Accrued Cost-of-Energy Revenue will be collected from retail electric customers over the next 20 months.

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, 2010 are related to forward purchases of energy scheduled for delivery through December 2013.

Unrecovered Project Costs—Big Stone II are costs incurred by OTP related to its participation in the planned construction of a 500- to 600-MW generating unit at its Big Stone Plant site. On September 11, 2009 OTP announced its withdrawal from participation in the Big Stone II project due to a number of factors. In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers over 36 months beginning in August 2010. The unrecovered balance of the North Dakota portion of costs as of December 31, 2010, of $3,460,000 will be recovered over the next 31 months. OTP has requested recovery of the Minnesota and South Dakota portions of Big Stone II development costs as part of its current general rate cases being conducted in those states and has deferred recognition of these costs as operating expenses pending determination of recoverability by the MPUC and the SDPUC.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of December 31, 2010. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over the next 39 months.

Deferred Conservation Program Costs & Accrued Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates within the next 18 months.

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

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 22 years.

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, 2010. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over the next 36 months.

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

General Rate Case Recoverable Expenses will be recovered over the next 40 months.

MISO Schedule 16 and 17 Deferred Administrative Costs—ND will be recovered over the next 23 months.

South Dakota—Asset-Based Margin Sharing Shortfall and Excess represent differences in OTP's South Dakota share of actual profit margins on wholesale sales of electricity from company-owned generating units and estimated profit margins from those sales that were used in determining current South Dakota retail electric rates. Net shortfalls or excess margins accumulated annually will be subject to recovery or refund through future retail rate adjustments in South Dakota in the following year.

Deferred Holding Company Formation Costs will be amortized over the next 42 months.

Minnesota Transmission Rider Accrued Revenues are expected to be recovered from Minnesota retail electric customers over the next 15 months.

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

The Deferred Gain on Sale of Utility Property will be paid to Minnesota retail electric customers over the next 23 years.

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, 2010 OTP had recognized, on a pretax basis, $763,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into level 2 of the fair value hierarchy set forth in ASC 820-10-35.

Electric operating revenues include $23,197,000 in 2010, $15,762,000 in 2009 and $27,236,000 in 2008 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts and sales of financial transmission rights and daily settlements of virtual transactions in the MISO market, broken down as follows for the years ended December 31:

(in thousands)	2010	2009	2008
Wholesale Sales—Company-Owned Generation	$ 20,053	$ 12,579	$ 23,708
Revenue from Settled Contracts at Market Prices	147,003	110,124	520,280
Market Cost of Settled Contracts	(145,994)	(109,125)	(518,866)
Net Margins on Settled Contracts at Market	1,009	999	1,414
Marked-to-Market Gains on Settled Contracts	18,901	14,585	39,375
Marked-to-Market Losses on Settled Contracts	(17,529)	(13,431)	(37,138)
Net Marked-to-Market Gain on Settled Contracts	1,372	1,154	2,237
Unrealized Marked-to-Market Gains on Open Contracts	6,700	8,097	405
Unrealized Marked-to-Market Losses on Open Contracts	(5,937)	(7,067)	(528)
Net Unrealized Marked-to-Market Gain (Loss) on Open Contracts	763	1,030	(123)
Wholesale Electric Revenue	$ 23,197	$ 15,762	$ 27,236

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, 2010 and December 31, 2009, and the change in the Company's consolidated balance sheet position from December 31, 2009 to December 31, 2010 and December 31, 2008 to December 31, 2009:

(in thousands)	December 31, 2010	December 31, 2009
Current Asset—Marked-to-Market Gain	$ 6,875	$ 8,321
Regulatory Asset—Deferred Marked-to-Market Loss	12,054	7,614
Total Assets	18,929	15,935
Current Liability—Marked-to-Market Loss	(17,991)	(14,681)
Regulatory Liability—Deferred Marked-to-Market Gain	(175)	(224)
Total Liabilities	(18,166)	(14,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 763	$ 1,030

(in thousands)	Year ended December 31, 2010	Year ended December 31, 2009
Fair Value at Beginning of Year	$ 1,030	$ (123)
Amount Realized on Contracts Entered into in Prior Year	389	123
Changes in Fair Value of Contracts Entered into in Prior Year	—	—
Net Fair Value of Contracts Entered into in Prior Year at Year End	641	—
Changes in Fair Value of Contracts Entered into in Current Year	122	1,030
Net Fair Value at End of Year	$ 763	$ 1,030

The $763,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2010 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	1st Qtr 2011	2nd Qtr 2011	3rd Qtr 2011	4th Qtr 2011	2012	Total
Net Gain	$ 97	$ 102	$ 140	$ 103	$ 321	$ 763

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, 2010 was $585,000. As of December 31, 2010 OTP had a net credit risk exposure of $1,129,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2010 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The $1,129,000 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, 2010. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $427,000 on certain OTP derivative energy contracts included in the $17,991,000 derivative liability on December 31, 2010 are covered by deposited funds. Certain other 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. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that were in a liability position on December 31, 2010 was $10,904,000, for which OTP had posted $6,219,000 as collateral in the form of offsetting gain positions on other contracts with its counterparties under master netting agreements. If the credit-risk-related contingent features underlying these agreements had been triggered on December 31, 2010, OTP would have been required to provide $4,685,000 in additional cash to its counterparties. The remaining derivative liability balance of $6,660,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2009 was $222,000. As of December 31, 2009 OTP had a net credit risk exposure of $387,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2009 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 $387,000 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, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $72,000 on certain OTP derivative energy contracts included in the $14,681,000 derivative liability on December 31, 2009 are covered by deposited funds. Certain other 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. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that were in a liability position on December 31, 2009 was $7,958,000, for which OTP had posted $7,760,000 as collateral in the form of offsetting gain positions on other contracts with one of its counterparties under a master netting agreement. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, OTP would have been required to provide $198,000 in additional cash to its counterparties. The remaining derivative liability balance of $6,651,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

Foreign Currency Exchange Forward Windows

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. IPH's Canadian subsidiary also entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in July 2009. Each monthly contract was for the exchange of $200,000 U.S. dollars for the amount of Canadian dollars stated in each contract. All contracts entered into in 2008 and 2009 were settled as of December 31, 2009. IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in May 2010 to cover the majority of its Canadian dollar cash needs from June 2010 through December 2010. Each contract was for the exchange of $250,000 U.S. dollars for the amount of Canadian dollars stated in each contract.

The following table lists the contracts entered into in 2008 and 2009 that were settled in 2009 and the contracts entered into in 2010 that were settled in 2010:

(in thousands)	Settlement Periods	USD	CAD
Contracts Entered into in July 2008	January 2009–July 2009	$2,800	$2,918
Mark-to-Market Losses on Open Contracts at Year End 2008	January 2009–July 2009	(401)	
Contracts Entered into in October 2008	January 2009–October 2009	$4,000	$5,001
Mark-to-Market Gains on Open Contracts at Year End 2008	January 2009–October 2009	112	
Net Mark-to-Market Losses Recognized on Open Contracts at Year End 2008		$ (289)	
Net Mark-to-Market Gains in 2009 on Open Contracts at Year End 2008		232	
Net Losses Realized on Settlement of 2008 Contracts in 2009		$ (57)	
Contracts Entered into in July 2009	August 2009–December 2009	$1,000	$1,163
Net Mark-to-Market Gains Recognized and Realized on Contracts Entered into in 2009		$ 88	
Net Mark-to-Market Gains Recognized in 2009		$ 320	
Net Mark-to-Market Gains Realized in 2009		$ 31	
Contracts Entered into in May 2010	June 2010–December 2010	$4,500	$4,680
Net Mark-to-Market Gains Recognized and Realized on Contracts Entered into in 2010		$ 35	

These contracts are derivatives subject to mark-to-market accounting. IPH did not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates. IPH settled these contracts during their stated settlement periods and used the proceeds to pay its Canadian liabilities when they came due. These contracts do not qualify for hedge accounting treatment because the timing of their settlements did not coincide with the payment of specific bills or contractual obligations. There were no foreign currency exchange forward windows outstanding as of December 31, 2010 or December 31, 2009. Realized net gains on IPH's foreign currency exchange forward windows of $35,000 for the year ended December 31, 2010 and $31,000 for the year ended December 31, 2009 are included in other income on the Company's consolidated statements of income.

6. COMMON SHARES AND EARNINGS PER SHARE

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

Common Share Distribution Agreement

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

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

The Company is not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement. The shares, if issued, will be issued pursuant to the Company's existing shelf registration statement, as amended. No shares were sold pursuant to the Agreement in 2010.

Following is a reconciliation of the Company's common shares outstanding from December 31, 2009 through December 31, 2010

Common Shares Outstanding, December 31, 2009	35,812,280
Issuances:	
Executive Officer Stock Awards on Resignation	70,400
Executive Officer Stock Performance Awards	34,768
Restricted Stock Issued to Employees	31,600
Stock Options Exercised	27,800
Restricted Stock Issued to Nonemployee Directors	24,800
Vesting of Restricted Stock Units	18,965
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(17,874)
Common Shares Outstanding, December 31, 2010	36,002,739

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 863,901 were still available as of December 31, 2010 under the Incentive Plan, which terminates on December 13, 2013.

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 145,760 were still available for purchase as of December 31, 2010. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, the Company purchased 82,857 common shares in the open market in 2010, issued 62,450 common shares and purchased 42,611 common shares in the open market in 2009 and purchased 49,684 common shares in the open market in 2008. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive during the investment period for the purpose of calculating diluted earnings per share.

Dividend Reinvestment and Share Purchase Plan

On August 30, 1996 the Company filed a shelf registration statement with the SEC for the issuance of up to 2,000,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders or customers who participate in the Plan to be either new issue common shares or common shares purchased in the open market. The Company's shelf registration statement expired on December 1, 2008 and was replaced by an automatically effective shelf registration statement filed by the Company on November 26, 2008 for the issuance of up to 1,000,000 common shares pursuant to the Plan. From November 2004 through April 2009 the Company had purchased common shares in the open market to provide shares for the Plan. From May 2009 through December 2009 the Company issued 233,943 common shares to provide shares for the Plan. In 2010 the Company purchased common shares in the open market to provide shares for the Plan.

Earnings Per Share

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

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the years ended December 31, 2010, 2009 and 2008:

Year	Options Outstanding	Range of Exercise Prices
2010	383,460	$24.93—$31.34
2009	415,710	$24.93—$31.34
2008	—	NA

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 $277,000 in 2010, $310,000 in 2009 and $275,000 in 2008. 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, 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, 2010:

Exercise Price	Outstanding and Exercisable as of 12/31/10	Remaining Contractual Life (yrs)
$ 24.93	21,800	4.3
$ 26.25	211,000	0.3
$ 26.495	20,600	3.3
$ 27.25	53,160	2.3
$ 28.665	3,000	0.8
$ 29.74	10,000	0.9
$ 31.34	63,900	1.3

Presented below is a summary of the stock options activity:

Stock Option Activity	2010		2009		2008	
	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	444,810	$ 26.82	507,702	$ 26.00	787,137	$ 25.73
Granted	—	—	—	—	—	—
Exercised	27,800	19.75	50,350	19.73	276,685	25.23
Forfeited	33,550	27.38	12,542	21.87	2,750	27.11
Outstanding, End of Year	383,460	27.28	444,810	26.82	507,702	26.00
Exercisable, End of Year	383,460	27.28	444,810	26.82	507,702	26.00
Cash Received for Options Exercised		$ 549,000		$ 994,000		$ 6,981,000
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 12, 2010 the Company's Board of Directors granted 24,800 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 2011 through 2014 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $21.835 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	2010		2009		2008	
	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	54,300	$ 27.81	39,300	$ 33.45	34,100	$ 30.80
Granted	24,800	21.835	28,800	22.15	20,000	35.345
Vested	19,375	28.98	13,800	32.06	14,800	29.92
Forfeited	—		—		—	
Nonvested, End of Year	59,725	24.95	54,300	27.81	39,300	33.45
Compensation Expense Recognized		$ 595,000		$ 535,000		$ 461,000
Fair Value of Shares Vested in Year		561,000		442,000		443,000

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 12, 2010 the Company's Board of Directors granted 31,600 shares of restricted stock to the Company's executive officers and OTP's president, under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2011 through 2014 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $21.835 per share, the average market price on the date of grant.

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

Employees' Restricted Stock Awards	2010		2009		2008	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Nonvested, Beginning of Year	50,478	$ 28.31	34,146	$ 34.72	24,058	$ 35.46
Granted	31,600	21.835	27,600	22.15	19,371	35.345
Variable/Liability Awards Vested	—		2,250	22.91	4,808	34.85
Nonvariable Awards Vested	15,917	29.76	9,018	35.84	4,475	35.80
Forfeited	—		—		—	
Nonvested, End of Year	66,161	24.79	50,478	28.31	34,146	34.72
Compensation Expense Recognized		$ 914,000		$ 439,000		$ 434,000
Fair Value of Variable Awards Vested/Liability Paid		—		52,000		168,000
Fair Value of Nonvariable Awards Vested		474,000		323,000		160,000

Restricted Stock Units Granted to Employees

On April 12, 2010 the Company's Board of Directors granted 26,180 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2014, the date the units vest. The grant date fair value of each restricted stock unit was $17.76 per share based on the market value of the Company's common stock on April 12, 2010, discounted for the value of the dividend exclusion over the four-year vesting period. The weighted average contractual term of stock units outstanding as of December 31, 2010 is 2.4 years.

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

Employees' Restricted Stock Unit Awards	2010		2009		2008	
	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	92,670	$ 25.42	73,585	$ 28.13	55,480	$ 26.66
Granted	26,180	17.76	29,515	18.86	26,650	30.92
Converted	18,965	23.93	5,350	24.94	3,850	25.93
Forfeited	20,570	25.55	5,080	27.33	4,695	28.07
Nonvested, End of Year	79,315	23.55	92,670	25.42	73,585	28.13
Compensation Expense Recognized		$ 250,000		$ 543,000		$ 535,000
Fair Value of Units Converted in Year		454,000		133,000		100,000

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under ASC 718 accounting requirements, the amount of compensation expense recorded related to awards granted is based on the estimated grant-date fair value of the awards as determined under a Monte Carlo valuation method for awards granted prior to 2009. The offsetting credit to amounts expensed related to the stock performance awards granted prior to 2009 is included in common shareholders' equity. The terms of the awards granted after 2008 are such that the entire award will be classified and accounted for as a liability, as required under ASC 718-10-25-18, and will be measured over the performance period based on the fair value of the award at the end of each reporting period subsequent to the grant date.

On April 12, 2010 the Company's Board of Directors granted performance share awards to the Company's executive officers under the Incentive Plan for the 2010-2012 performance measurement period.

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

Performance Period	Maximum Shares Subject To Award	Shares Used To Estimate Expense	Fair Value	Expense Recognized in the Year Ended December 31, 2010	2009	2008	Shares Awarded
2010–2012	146,800	73,400	$ 20.97	$ 513,000	$ —	$ —	22,500
2009–2011	181,200	90,600	$ 27.98	(178,000)	845,000	—	29,300
2008–2010	114,800	70,843	$ 37.59	888,000	888,000	888,000	18,600
2007–2009	109,000	67,263	$ 38.01	—	852,000	852,000	34,768
2006–2008	88,050	58,700	$ 25.95	—	—	508,000	29,350
Total				$ 1,223,000	$ 2,585,000	$ 2,248,000	134,518

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 and 2010-2012 performance periods reflect only shares received under the executive employment agreement. The Company's 2008-2010 total shareholder return ranking resulted in no incentive share awards for the Company's active plan participants for the 2008-2010 performance measurement period.

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

As of December 31, 2010 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 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, 2010.

9. COMMITMENTS AND CONTINGENCIES

Electric Utility Construction Contracts, Capacity and Energy Requirements and Coal and Delivery Contracts

At December 31, 2010 OTP had commitments under contracts in connection with construction programs aggregating approximately $8,393,000. For capacity and energy requirements, OTP has agreements extending through 2032 at annual costs of approximately $20,134,000 in 2011, $21,637,000 in 2012, $16,492,000 in 2013, $15,388,000 in 2014, $12,307,000 in 2015 and $78,879,000 for the years beyond 2015.

OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2011, 2012 and 2016. In total, OTP is committed to the minimum purchase of approximately $115,749,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

IPH Potato Supply and Fuel Purchase Commitments

IPH has commitments of approximately $10,000,000 for the purchase of a portion of its 2011 raw potato supply requirements and approximately $900,000 for the firm purchase of natural gas to cover a portion of its anticipated natural gas needs in Ririe, Idaho through September 2011.

Operating Lease Commitments

The amounts of future operating lease payments are as follows:

(in thousands)	Electric	Nonelectric	Total
2011	$ 2,335	$ 23,423	$ 25,758
2012	1,356	14,267	15,623
2013	933	9,327	10,260
2014	944	5,912	6,856
2015	955	4,453	5,408
Later years	14,702	8,070	22,772
Total	$ 21,225	$ 65,452	$ 86,677

The electric future operating lease payments are primarily related to land leases and coal rail-car leases. The nonelectric future operating lease payments are primarily related to leases of buildings, medical imaging equipment and transportation equipment. Rent expense from continuing operations was $39,571,000, $50,293,000 and $50,761,000 for 2010, 2009 and 2008, respectively.

Sierra Club Complaint

On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the CAA and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the CAA and the South Dakota SIP. The Sierra Club alleged the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the CAA and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009 the U.S. District Court for the District of South Dakota (Northern Division) issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a Motion for Reconsideration of the Amended Memorandum and Order. The District Court denied the motion on July 22, 2009. On July 30, 2009 the Sierra Club appealed the District Court's decision to the U. S. Court of Appeals for the 8th Circuit. On August 12, 2010 the U.S. Court of Appeals for the 8th Circuit affirmed the District Court decision dismissing the Sierra Club's suit against Big Stone Plant. The District Court's decision is now final because the Sierra Club did not file a petition for rehearing with the Court of Appeals and did not petition for writ of certiorari with the U.S. Supreme Court by the respective deadlines.

Federal Power Act Complaint

On August 29, 2008 Renewable Energy System Americas, Inc. (RES), a developer of wind generation, and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with the FERC alleging that OTP and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES and PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by OTP and NextEra Energy Resources, Inc. (fka FPL Energy, Inc.) (NextEra). RES and PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that OTP, Minnkota and NextEra pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that the FERC assess civil penalties against OTP. OTP answered the complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the complaint. On October 14, 2008, RES and PEAK Wind filed an answer to OTP's answer and, restated the allegations included in the initial complaint. RES and PEAK Wind also added a request that the FERC rescind both OTP's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, OTP filed a reply, denying the allegations made by RES and PEAK Wind in its answer. By order issued on December 19, 2008, the FERC set the complaint for hearing and established settlement procedures. A formal settlement agreement was filed with the FERC requesting approval of the settlement and withdrawal of the complaint. On May 6, 2010 the FERC issued an order approving the settlement and terminating the proceeding. The settlement did not have a material impact on OTP's financial position, results of operations or cash flows.

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, 2010 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, 2010 and December 31, 2009:

(in thousands)	Line Limit	In Use on December 31, 2010	Restricted Due to Outstanding Letters of Credit	Available on December 31, 2010	Available on December 31, 2009
Otter Tail Corporation Credit Agreement	$ 200,000	$ 54,176	$ 1,474	$ 144,350	$ 179,755
OTP Credit Agreement	170,000	25,314	250	144,436	167,735
Total	$ 370,000	$ 79,490	$ 1,724	$ 288,786	$ 347,490

The weighted average interest rates on consolidated short-term debt outstanding on December 31, 2010 and 2009 were 2.6% and 2.2%, respectively. The weighted average interest rate paid on consolidated short-term debt was 2.2% in 2010 and 2.4% in 2009.

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

OTP is the borrower under a $170 million credit agreement (the OTP Credit Agreement) with an accordion feature whereby the line can be increased to $250 million as 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 $50,000,000 outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP pays utilization fees when usage of the revolving credit facility exceeds 50% of the commitments of the lenders and pays facility fees based on the average daily amount outstanding under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default. The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the borrower's credit ratings. The OTP Credit Agreement is subject to renewal on July 30, 2011. The Company is in the process of renewing the OTP Credit Agreement and has signed a term sheet with an agent bank. The term sheet calls for a five-year term facility with borrowings priced at LIBOR plus 1.5%, subject to adjustment based on the ratings of OTP's senior unsecured debt. All other terms in the term sheet are substantially the same as in the current OTP Credit Agreement.

LONG-TERM DEBT

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

OTP's Senior Unsecured Notes 6.63% due December 1, 2011 remain classified as long-term debt because OTP has the ability to refinance this debt under the OTP Credit Agreement scheduled for renewal in July 2011.

9.000% Notes due 2016

On December 4, 2009 the Company issued $100 million of its 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 the Company and U.S. Bank National Association (formerly First Trust National Association), as trustee. The notes are unsecured indebtedness and bear interest at 9.000% per year, payable semi-annually in arrears on June 15 and December 15 of each year, beginning June 15, 2010. The entire principal amount of the notes, unless previously redeemed or otherwise repaid, will mature and become due and payable on December 15, 2016. The net proceeds from the issuance of approximately $98.3 million, after deducting the underwriting discount and offering expenses, were used to repay the Company's revolving credit facility, which had an outstanding balance due of $107.0 million on November 30, 2009 at an interest rate of approximately 2.6%. The Company used approximately $44.5 million of the borrowings under its revolving credit facility to fund costs incurred for the expansion of its subsidiary companies' manufacturing facilities in 2008 and 2009. The Company used approximately $23.0 million to fund the acquisition of Miller Welding in 2008 and approximately $28.5 million in connection with the capitalization of its holding company reorganization in 2009.

Term Loan Agreement and Retirement

Prior to the Company's holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $75 million term loan agreement (the OTP Loan Agreement). The OTP Loan Agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein. On completion of the Company's holding company formation on July 1, 2009, the OTP Loan Agreement became an obligation of OTP. The OTP Loan Agreement provided for a $75 million term loan due May 20, 2011. The proceeds were used to support OTP's construction of 49.5 MW of renewable wind-generation assets at the Luverne Wind Farm. In November 2009, OTP paid down $17 million of the $75 million term loan. OTP paid off the remaining $58 million balance in January 2010, using lower cost funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayments and retirement of its debt under the OTP Loan Agreement.

Borrowings under the OTP Loan Agreement bore interest at a rate equal to the base rate in effect from time to time. The base rate was a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A.'s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of OTP's senior unsecured credit ratings, as provided in the Loan Agreement. The interest rate on borrowings under the OTP Loan Agreement was 3.73% at December 31, 2009.

Other Debt Retirement

In June 2009, the Company paid $3,493,000 to retire early its Lombard US Equipment Finance note due October 2, 2010. No penalty was paid for early retirement of the note.

2001 and 2007 Note Purchase Agreements

The note purchase agreement relating to OTP's $90 million 6.63% senior notes due December 1, 2011, as amended (the 2001 Note Purchase Agreement) and 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) each states that the applicable obligor may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the applicable obligor to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states the applicable obligor 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 such obligor. The 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement each contain a number of restrictions on the applicable obligor and its subsidiaries. These include restrictions on the obligor's ability and the ability of the obligor's subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

Cascade Note Purchase Agreement

The Note Purchase Agreement dated as of February 23, 2007 with Cascade Investment, L.L.C., as amended (the Cascade Note Purchase Agreement), states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The Cascade Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the Cascade Note Purchase Agreement. The Cascade Note Purchase Agreement contains a number of restrictions on the businesses of the Company and its subsidiaries. These include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Under the Cascade Note Purchase Agreement, as amended, the Company may not permit the aggregate principal amount of all debt of OTP and its subsidiaries to exceed 60% of Otter Tail Consolidated Total Capitalization (as defined in the Cascade Note Purchase Agreement, as amended by Amendment No. 2), determined as of the end of each fiscal quarter of the Company. In addition, the interest rate applicable to the Cascade Note was increased to 8.89% per annum which is reflective of the Company's new senior unsecured debt ratings. The obligations of the Company under the Cascade Note Purchase Agreement and the Cascade Note are guaranteed by Varistar Corporation and certain of its subsidiaries. Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2010.

On June 23, 2010 the Company entered into Amendme[illegible] Cascade Note Purchase Agreement. Amendment No. 3 amends cer[illegible] covenants and related definitions contained in the Cascade Note Purchase Agreement to, among other things, provide the Company and its material subsidiaries with additional flexibility to incur certain customary liens, make certain investments, and give certain guaranties, in each case under the circumstances set forth in Amendment No. 3. On July 29, 2010 the Company entered into Amendment No. 4 to the Cascade Note Purchase Agreement, which was effective June 30, 2010. The amendments contained in Amendment No. 4 permit the Company to exclude impairment charges and write-offs of assets (including ShoreMaster's June 2010 asset impairment charge), from the calculation of the interest charges coverage ratio required to be maintained under the Cascade Note Purchase Agreement.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2010 for each of the next five years are $90,631,000 for 2011, $13,479,000 for 2012, $418,000 for 2013, $578,000 for 2014 and $0 for 2015.

FINANCIAL COVENANTS

As of December 31, 2010 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 Credit Agreement relating to the $200 million credit facility of the Company, 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 Credit Agreement.
- Under the Cascade Note Purchase Agreement, the Company may not permit its ratio of Consolidated Debt to Consolidated Total Capitalization to be greater than 0.60 to 1.00 or its Interest Charges Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis), permit the ratio of OTP's Debt to OTP's Total Capitalization to be greater than 0.60 to 1.00, or permit Priority Debt to exceed 20% of Varistar Consolidated Total Capitalization, as provided in the Cascade Note Purchase Agreement.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the Loan Agreement.
- Under the 2001 Note Purchase Agreement, the 2007 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 (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges 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 2001 Note Purchase Agreement and the 2007 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 connection with the acquisition of IPH in August 2004, IPH management and certain other employees elected to retain stock options for the purchase of IPH Class B common shares valued at $1.8 million. The options are exercisable at any time and the option holder must deliver cash to exercise the option. Once the options are exercised for Class B shares, the Class B shareholder cannot put the shares back to the Company for 181 days. At that time, the Class B common shares are redeemable at any time during the employment of the individual holder, subject to certain limits on the total number of Class B common shares redeemable on an annual basis. The Class B common shares are nonvoting, except in the event of a merger, and do not participate in dividends but have liquidation rights at par with the Class A common shares owned by the Company. The value of the Class B common shares issued on exercise of the options represents an interest in IPH that changes as defined in the agreement.

In May 2010, an employee of IPH exercised options to purchase 400 IPH Class B common shares at a combined exercise price of $153,000. The book value of the options exercised totaled $681,000 based on an IPH Class B common share value of $2,085.88 per share. The fair value of IPH Class B common shares on the exercise date was $2,485.60 per share. The IPH Class B common shares issued were recorded at their exercise-date fair value of $994,000. The $96,000 net-of-tax difference between the fair value of the shares issued and book-value basis of the options exercised was charged to retained earnings and earnings available for common shares were reduced for the year ended December 31, 2010. In June 2010, IPH exercised its right to repurchase the 400 outstanding IPH Class B common shares for $994,000 in cash and the shares were retired.

In July 2010, IPH bought back nine options to purchase IPH Class B common shares from a former employee for $18,000, the fair value of the options. The book value of the options totaled $14,000. The $2,000 net-of-tax 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 $2,000 for the year ended December 31, 2010.

As of December 31, 2010 there were 363 options for the purchase of IPH Class B common shares outstanding with a combined exercise price of $233,000. All 363 outstanding options were "in-the-money" on December 31, 2010. A valuation of IPH Class B common shares in the first quarter of 2010 indicated a fair value of $2,485.60 per share. The book value of outstanding IPH Class B common share options on December 31, 2010 is based on an IPH Class B common share value of $2,085.88 per share.

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. 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)	2010	2009	2008
Service Cost—Benefit Earned During the Period	$ 4,654	$ 4,180	$ 4,630
Interest Cost on Projected Benefit Obligation	12,067	11,943	11,325
Expected Return on Assets	(13,711)	(13,779)	(13,968)
Amortization of Prior-Service Cost	683	724	742
Amortization of Net Actuarial Loss	2,002	77	169
Net Periodic Pension Cost	$ 5,695	$ 3,145	$ 2,898

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

	2010	2009	2008
Discount Rate	6.00%	6.70%	6.25%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%	3.75%

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

(in thousands)	2010	2009
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 1,930	$ 2,597
Unrecognized Actuarial Loss	64,396	69,378
Total Regulatory Assets	66,326	71,975
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	35	45
Unrecognized Actuarial Loss	667	1,199
Total Accumulated Other Comprehensive Loss	702	1,244
Deferred Income Taxes	468	829
Noncurrent Liability	$ 45,741	$ 66,598

Funded status as of December 31:

(in thousands)	2010	2009
Accumulated Benefit Obligation	$ (183,174)	$ (167,195)
Projected Benefit Obligation	$ (217,049)	$ (207,145)
Fair Value of Plan Assets	171,308	140,547
Funded Status	$ (45,741)	$ (66,598)

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, 2010:

(in thousands)	2010	2009
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 140,547	$ 127,535
Actual Return on Plan Assets	19,883	17,886
Discretionary Company Contributions	20,000	4,000
Benefit Payments	(9,122)	(8,874)
Fair Value of Plan Assets at December 31	$ 171,308	$ 140,547
Estimated Asset Return	13.62%	14.30%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 207,145	$ 182,559
Service Cost	4,654	4,180
Interest Cost	12,067	11,943
Benefit Payments	(9,122)	(8,874)
Actuarial Loss	2,305	17,337
Projected Benefit Obligation at December 31	$ 217,049	$ 207,145

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

	2010	2009
Discount Rate	6.00%	6.00%
Rate of Increase in Future Compensation Level	3.75%	3.75%

To develop the expected long-term rate of return on assets assumption, the Company considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio.

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.

The assumed rate of return on pension fund assets for the determination of 2011 net periodic pension cost is 8.00%.

Measurement Dates:	2010	2009
Net Periodic Pension Cost	January 1, 2010	January 1, 2009
End of Year Benefit Obligations	January 1, 2010 projected to December 31, 2010	January 1, 2009 projected to December 31, 2009
Market Value of Assets	December 31, 2010	December 31, 2009

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 2011 are:

(in thousands)	2011
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 424
Amortization of Unrecognized Actuarial Loss	2,538
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	10
Amortization of Unrecognized Actuarial Loss	62
Total Estimated Amortization	$ 3,034

Cash flows—The Company is not required to make a contribution to the pension plan in 2011.

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

(in thousands)		**Years**			
2011	2012	2013	2014	2015	2016-2020
$ 9,698	$ 10,031	$ 10,409	$ 10,786	$ 11,405	$ 69,045

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 Retirement Plans Administrative Committee (RPAC) 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 RPAC 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 revised Investment Policy Statement recently approved by the RPAC. Each of the asset categories is within its respective tactical range. The RPAC monitors actual asset allocations and directs contributions and withdrawals toward maintaining the current targeted allocation percentages listed below.

Asset Allocation	Strategic Target	Tactical Range
Equity Securities	51%	41%–61%
Fixed-Income Securities	44%	34%–54%
Enhanced Return	5%	0%–12%
Cash	0%	0%–5%

The Company's pension plan asset allocations at December 31, 2010 and 2009, by asset category are as follows:

Asset Allocation	2010	2009
Large Capitalization Equity Securities	26.7%	32.0%
International Equity Securities	16.8%	20.2%
Small and Mid Capitalization Equity Securities	7.0%	13.5%
Equity Securities	50.5%	65.7%
Fixed-Income Securities and Cash	49.5%	34.3%
	100.0%	100.0%

Fair Value Measurements of Pension Fund Assets

ASC 820 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. ASC 820-10-35 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

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

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

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

The following table presents, for each of these hierarchy levels, the

Company's pension fund assets measured at fair value as of December 31, 2010 and 2009:

2010 *(in thousands)*	Level 1	Level 2	Level 3
Large Capitalization Equity Securities	$ 45,861		
International Equity Securities	28,755		
Small and Mid Capitalization Equity Securities	11,963		
Fixed Income Securities	75,447		
Cash Management—Working Capital Accounts	8,403	$ 879	
Total Assets	$ 170,429	$ 879	

2009 *(in thousands)*	Level 1	Level 2	Level 3
Mutual Funds	$ 58,683		
Corporate Stocks—Common	24,687		
U.S. Government Securities	29,356		
Corporate Debt Securities	10,616		
Fixed Income—Municipal Bonds	216		
Interest-Bearing Cash	1		
Common Collective Trusts		$ 16,140	
Collateral Held on Loaned Securities		208	
Other		640	
Total Assets	$ 123,559	$ 16,988	

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)	2010	2009	2008
Service Cost—Benefit Earned During the Period	$ 660	$ 752	$ 691
Interest Cost on Projected Benefit Obligation	1,670	1,694	1,535
Amortization of Prior-Service Cost	74	71	66
Amortization of Net Actuarial Loss	477	385	480
Net Periodic Pension Cost	$ 2,881	$ 2,902	$ 2,772

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

	2010	2009	2008
Discount Rate	6.00%	6.70%	6.25%
Rate of Increase in Future Compensation Level	4.69%	4.70%	4.70%

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

(in thousands)	2010	2009
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 343	$ 389
Unrecognized Actuarial Loss	3,024	4,433
Total Regulatory Assets	3,367	4,822
Projected Benefit Obligation Liability—Net Amount Recognized	(27,797)	(28,441)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	151	167
Unrecognized Actuarial Loss	1,324	1,910
Total Accumulated Other Comprehensive Loss	1,475	2,077
Deferred Income Taxes	984	1,385
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (21,971)	$ (20,157)

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, 2010 and a statement of the funded status as of December 31 of both years:

(in thousands)	2010	2009
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Employer Contributions	1,067	1,112
Benefit Payments	(1,067)	(1,112)
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 28,441	$ 25,888
Service Cost	660	752
Interest Cost	1,670	1,694
Benefit Payments	(1,067)	(1,112)
Plan Amendments	—	41
Actuarial (Gain) Loss	(1,907)	1,178
Projected Benefit Obligation at December 31	$ 27,797	$ 28,441
Reconciliation of Funded Status:		
Funded Status at December 31	$ (27,797)	$ (28,441)
Unrecognized Net Actuarial Loss	5,232	7,616
Unrecognized Prior Service Cost	594	668
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (21,971)	$ (20,157)

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

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

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 2011 are:

(in thousands)	2011
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 42
Amortization of Unrecognized Actuarial Loss	142
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	31
Amortization of Unrecognized Actuarial Loss	103
Total Estimated Amortization	$ 318

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)		Years			
2011	2012	2013	2014	2015	2016-2020
$1,121	$ 1,249	$ 1,242	$ 1,251	$ 1,420	$ 7,476

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)	2010	2009	2008
Service Cost—Benefit Earned During the Period	$ 1,634	$ 1,172	$ 1,103
Interest Cost on Projected Benefit Obligation	3,207	2,935	2,689
Amortization of Transition Obligation	748	748	748
Amortization of Prior-Service Cost	211	211	211
Amortization of Net Actuarial Loss	832	—	26
Expense Decrease Due to Medicare Part D Subsidy	(2,078)	(1,335)	(1,172)
Net Periodic Postretirement Benefit Cost	$ 4,554	$ 3,731	$ 3,605

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

	2010	2009	2008
Discount Rate	5.75%	6.70%	6.25%

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

(in thousands)	2010	2009
Regulatory Asset:		
Unrecognized Transition Obligation	$ 727	$ 1,093
Unrecognized Prior Service Cost	1,155	1,361
Unrecognized Net Actuarial Loss (Gain)	2,580	(379)
Net Regulatory Asset	4,462	2,075
Projected Benefit Obligation Liability—Net Amount Recognized	(42,372)	(37,712)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	462	691
Unrecognized Prior Service Cost	21	24
Unrecognized Net Actuarial Gain	(82)	(7)
Accumulated Other Comprehensive Loss	401	708
Deferred Income Taxes	267	472
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (37,242)	$ (34,457)

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, 2010:

(in thousands)	2010	2009
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Company Contributions	1,769	1,254
Benefit Payments (Net of Medicare Part D Subsidy)	(3,748)	(3,113)
Participant Premium Payments	1,979	1,859
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 37,712	$ 32,621
Service Cost (Net of Medicare Part D Subsidy)	1,371	960
Interest Cost (Net of Medicare Part D Subsidy)	2,224	2,027
Benefit Payments (Net of Medicare Part D Subsidy)	(3,748)	(3,113)
Participant Premium Payments	1,979	1,859
Actuarial Loss	2,834	3,358
Projected Benefit Obligation at December 31	$ 42,372	$ 37,712
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (34,457)	$ (31,980)
Expense	(4,554)	(3,731)
Net Company Contribution	1,769	1,254
Accrued Postretirement Cost at December 31	$ (37,242)	$ (34,457)

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

	2010	2009
Discount Rate	5.75%	5.75%

Assumed healthcare cost-trend rates as of December 31:

	2010	2009
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.94%	7.10%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.42%	7.63%
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 2010 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 4,991	$ (4,179)
Effect on Total of Service and Interest Cost	$ 572	$ (461)
Effect on Expense	$ 734	$ (461)

Measurement Dates:	2010	2009
Net Periodic Postretirement Benefit Cost	January 1, 2010	January 1, 2009
End of Year Benefit Obligations	January 1, 2010 projected to December 31, 2010	January 1, 2009 projected to December 31, 2009

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 2011 are:

(in thousands)	2011
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 365
Amortization of Unrecognized Prior Service Cost	205
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	383
Amortization of Unrecognized Prior Service Cost	5
Total Estimated Amortization	$ 958

Cash flows—The Company expects to contribute $2.3 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2011. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $520,000 in 2011. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)			Years		
2011	2012	2013	2014	2015	2016-2020
$2,324	$ 2,429	$ 2,539	$ 2,691	$ 2,813	$ 16,405

LEVERAGED EMPLOYEE STOCK OWNERSHIP PLAN

The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $779,000 for 2010, $761,000 for 2009 and $738,000 for 2008.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

Long-Term Debt—The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. About $10.4 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

	December 31, 2010		December 31, 2009	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ —	—	$ 4,432	$ 4,432
Long-Term Debt	(435,446)	(474,941)	(436,170)	(457,907)

14. PROPERTY, PLANT AND EQUIPMENT

(in thousands)	December 31, 2010	December 31, 2009
Electric Plant in Service		
Production	$ 660,488	$ 660,654
Transmission	218,221	216,508
Distribution	373,180	357,623
General	81,085	78,230
Electric Plant in Service	1,332,974	1,313,015
Construction Work in Progress	27,788	11,104
Total Gross Electric Plant	1,360,762	1,324,119
Less Accumulated Depreciation and Amortization	476,188	446,008
Net Electric Plant	$ 884,574	$ 878,111
Nonelectric Operations Plant		
Equipment	$ 275,462	$ 244,419
Buildings and Leasehold Improvements	97,960	96,899
Land	21,034	20,770
Nonelectric Operations Plant	394,456	362,088
Construction Work in Progress	15,269	12,259
Total Gross Nonelectric Plant	409,725	374,347
Less Accumulated Depreciation and Amortization	185,648	153,831
Net Nonelectric Operations Plant	$ 224,077	$ 220,516
Net Plant	$ 1,108,651	$ 1,098,627

The estimated service lives for rate-regulated properties is 5 to 65 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

(years)	Service Life Range Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65
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 2010, 2009 and 2008) to net income before total income tax expense for the following reasons:

(in thousands)	2010	2009	2008
Tax Computed at Federal Statutory Rate	$ 913	$ 7,499	$ 17,556
Increases (Decreases) in Tax from:			
Income Taxes on Valuation Allowances	5,549	—	—
Book Write-off of Intangible Impairment	3,309	—	—
Impact of Medicare Part D Change	1,692		
Foreign Tax Rate Reduction True-up	1,143	—	—
Differences Reversing in Excess of Federal Rates	989	893	1,089
Federal Production Tax Credit	(6,441)	(6,533)	(3,234)
North Dakota Wind Tax Credit Amortization—Net of Federal Taxes	(1,163)	(870)	(369)
State Income Taxes Net of Federal Income Tax Benefit	(1,132)	1,871	2,608
Investment Tax Credit Amortization	(926)	(992)	(1,125)
Tax Depreciation—Treasury Grant for Wind Farms	(845)	(3,169)	—
Dividend Received/Paid Deduction	(692)	(683)	(718)
Corporate Owned Life Insurance	(556)	(973)	814
Allowance for Funds Used During Construction—Equity	(1)	(1,113)	(975)
Permanent and Other Differences	2,112	(535)	(609)
Total Income Tax Expense (Benefit)	$ 3,951	$ (4,605)	$ 15,037
Overall Effective Federal, State and Foreign Income Tax Rate	151.5%	(21.5)%	30.0%
Income Tax Expense Includes the Following:			
Current Federal Income Taxes	$ (5,877)	$ (41,353)	$ (20,066)
Current State Income Taxes	3,907	3,492	(1,115)
Deferred Federal Income Taxes	14,474	42,470	39,051
Deferred State Income Taxes	(3,760)	(571)	5,280
Foreign Income Taxes	3,737	(248)	(3,385)
Federal Production Tax Credit	(6,441)	(6,533)	(3,234)
North Dakota Wind Tax Credit Amortization—Net of Federal Taxes	(1,163)	(870)	(369)
Investment Tax Credit Amortization	(926)	(992)	(1,125)
Total	$ 3,951	$ (4,605)	$ 15,037
Income Before Income Taxes—U.S.	$ 13,670	$ 22,060	$ 58,615
Loss Before Income Taxes—Foreign	(11,063)	(634)	(8,453)
Total Income Before Income Taxes	$ 2,607	$ 21,426	$ 50,162

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

(in thousands)	2010	2009
Deferred Tax Assets		
Related to North Dakota Wind Tax Credits	$ 57,564	$ 58,191
Benefit Liabilities	36,037	36,329
ASC 715 Liabilities	29,092	24,946
Cost of Removal	24,326	23,253
Federal Production Tax Credits	13,072	6,533
Net Operating Loss Carryforward		
(Net of Valuation Allowance $5,549 for 2010)	12,501	12,757
Differences Related to Property	11,748	11,445
Amortization of Tax Credits	4,290	4,966
Vacation Accrual	3,164	2,872
Other	8,038	5,940
Total Deferred Tax Assets	$ 199,832	$ 187,232
Deferred Tax Liabilities		
Differences Related to Property	$ (286,611)	$ (269,718)
ASC 715 Regulatory Asset	(29,092)	(24,946)
Related to North Dakota Wind Tax Credits	(15,132)	(16,116)
Transfer to Regulatory Asset	(7,920)	(5,808)
Excess Tax over Book Pension	(8,656)	(2,969)
Renewable Resource Rider Accrued Revenue	(3,625)	(2,300)
Impact of State Net Operating Losses on		
Federal Taxes	(1,992)	(2,060)
Other	(9,346)	(7,164)
Total Deferred Tax Liabilities	$ (362,374)	$ (331,081)
Deferred Income Taxes	$ (162,542)	$ (143,849)

Schedule of expiration of tax net operating losses and tax credits:

		Year of Expiration					
(in thousands)	Amount	2012	2013	2014	2015	2016	2024-33
United States:							
Federal Net Operating Losses	$ 439	$ —	$ —	$ —	$ —	$ —	$ 439
Federal Tax Credits	13,712	—	—	—	—	—	13,712
State Net Operating Losses	9,531	—	—	—	—	—	9,531
State Tax Credits	43,312	511	1,950	1,950	1,950	1,950	35,001
Canada							
Net Operating Losses	8,824	—	—	—	—	—	8,824
Tax Credits	674	—	—	—	—	—	674

As of December 31, 2010, the Company established a valuation allowance related to certain of the foreign net operating loss carryforwards. The valuation allowance represents a provision for uncertainty as to the realization of the tax benefits of these carryforwards. The valuation allowance will be reduced when and if the Company determines it is more likely than not that the related deferred income tax assets will be realized.

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

(in thousands)	2010	2009	2008
Balance on January 1	$ 900	$ 284	$ 506
Increases Related to Tax Positions	—	900	—
Uncertain Positions Resolved During Year	—	(284)	(222)
Balance on December 31	$ 900	$ 900	$ 284

The balance of unrecognized tax benefits as of December 31, 2010 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2010 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. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2010 were not material.

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, 2010, with limited exceptions, the Company is no longer subject to examinations for tax years prior to 2006, for all jurisdictions.

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 site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. 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 2010.

During 2009, OTP recorded new obligations related to the removal of 33 wind turbines and restoration of its tower sites located at the Luverne Wind Farm in Steele County, North Dakota, and for future renovations of areas currently occupied by various water treatment sludge ponds at the Big Stone Plant site. OTP determined the fair value of its future obligations related to the removal of its 33 wind turbines located at the Luverne Wind Farm by engaging an outside engineering firm with expertise in demolition and removal to provide an estimate of the current costs to remove these assets, then projected the costs forward to 2034 using an inflation rate of 2.9% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 8.3%. OTP determined the fair value of its future obligations for future renovations of areas currently occupied by various water treatment sludge ponds by conducting an internal assessment incorporating the services of a local contractor to estimate the current cost to renovate these areas. OTP then projected the costs forward to 2024 using an inflation rate of 2.7% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 8.75%.

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, 2010 and 2009 are presented in the following table:

(in thousands)	2010	2009
Asset Retirement Obligations		
Beginning Balance	$ 4,050	$ 3,298
New Obligations Recognized	—	436
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Accrued Accretion	352	316
Settlements	—	—
Ending Balance	$ 4,402	$ 4,050
Asset Retirement Costs Capitalized		
Beginning Balance	$ 1,497	$ 1,061
New Obligations Recognized	—	436
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Settlements	—	—
Ending Balance	$ 1,497	$ 1,497
Accumulated Depreciation—Asset Retirement Costs Capitalized		
Beginning Balance	$ 233	$ 179
New Obligations Recognized	—	—
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Accrued Depreciation	57	54
Settlements	—	—
Ending Balance	$ 290	$ 233
Settlements		
Original Capitalized Asset Retirement Cost—Retired	$ —	$ —
Accumulated Depreciation	—	—
Asset Retirement Obligation	$ —	$ —
Settlement Cost	—	—
Gain on Settlement—Deferred Under Regulatory Accounting	$ —	$ —

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.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2010	2009	2010 (1)	2009	2010	2009	2010 (2)	2009
Operating Revenues	$ 262,186	$ 277,239	$ 270,195	$ 246,857	$ 280,667	$ 257,440	$ 306,036	$ 257,976
Operating Income (Loss)	15,991	8,609	(13,143)	6,180	14,808	17,496	16,857	13,105
Net Income (Loss)	4,717	4,388	(14,218)	2,731	6,101	10,592	2,056	8,320
Earnings (Loss) Available for Common Shares	4,533	4,204	(14,497)	2,547	5,914	10,408	1,873	8,136
Basic Earnings (Loss) Per Share	$ .13	$ .12	$ (.40)	$ .07	$ .17	$ .29	$ .05	$ .23
Diluted Earnings (Loss) Per Share	$ .13	$ .12	$ (.40)	$ .07	$ .16	$ .29	$ .05	$ .23
Dividends Paid Per Common Share	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975	$ .2975
Price Range:								
High	25.39	24.50	23.10	24.05	21.19	25.40	23.33	25.34
Low	19.70	15.47	18.46	18.63	18.24	20.73	20.03	22.37
Average Number of Common Shares Outstanding—Basic	35,721	35,325	35,799	35,389	35,806	35,528	35,808	35,611
Average Number of Common Shares Outstanding—Diluted	35,940	35,489	35,799	35,644	36,076	35,788	36,036	35,866

Notes: (1) Results include a $19.7 million asset impairment charge at ShoreMaster.
(2) Results include a $6.6 million increase in income tax expense at DMI's Canadian operations due to the establishment of a $5.5 million valuation allowance against deferred tax assets related to operating loss carryforwards and a $1.1 million reversal of deferred tax assets related to a reduction in statutory tax rates in Canada.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosures Controls and Procedures. Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2010, 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, 2010.

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, 2010 that has materially affected, or is 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, 2010. 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, 2010, 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 52.

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 2011 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 2011 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 2011 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 2011 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 2011 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 2011 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 2011 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2010 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	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity Compensation Plans Approved by Security Holders:			
1999 Stock Incentive Plan	711,213 (1)	$14.71	863,901 (2)
1999 Employee Stock Purchase Plan	—	N/A	145,760 (3)
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	711,213	$14.71	1,009,661

(1) Includes 101,800, and 122,600 performance based share awards made in 2010 and 2009, respectively, 79,315 restricted stock units outstanding as of December 31, 2010, and 24,038 phantom shares as part of the deferred director compensation program, 383,460 outstanding options as of December 31, 2010 and excludes 125,886 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 2011 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 2011 Annual Meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. Financial Statements

2. Financial Statement Schedules

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

3. Exhibits

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

	PREVIOUSLY FILED		
	FILE NO.	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-1	10-K for year ended 12/31/01	4-D-7	Note Purchase Agreement, dated as of December 1, 2001.
4-A-2	10-K for year ended 12/31/02	4-D-4	First Amendment, dated as of December 1, 2002, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-3	10-Q for quarter ended 9/30/04	4.2	Second Amendment, dated as of October 1, 2004, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-4	8-K filed 12/20/07	4.2	Third Amendment, dated as of December 1, 2007, to Note Purchase Agreement, dated as of December 1, 2001.
4-A-5	8-K filed 7/01/09	4.1	Fourth Amendment, dated as of June 30, 2009, to Note Purchase Agreement dated as of December 1, 2001.
4-B	8-K filed 8/01/08	4.1	Credit Agreement, dated as of July 30, 2008, among Otter Tail Corporation, dba Otter Tail Power Company (now known as Otter Tail Power Company), the Banks named therein, Bank of America, N.A., as Syndication Agent, and U.S. Bank National Association, as agent for the Banks.
4-B-1	8-K filed 4/24/09	4.2	First Amendment, dated as of April 21, 2009, to Credit Agreement, dated as of July 30, 2008.
4-C	8-K filed 2/28/07	4.1	Note Purchase Agreement, dated as of February 23, 2007, between the Company and Cascade Investment L.L.C.
4-C-1	8-K filed 7/01/09	4.3	Amendment No. 2, dated as of June 30, 2009, to Note Purchase Agreement, dated as of February 23, 2007.
4-C-2	8-K filed 6/29/10	4.2	Amendment No. 3, dated as of June 23, 2010, to Note Purchase Agreement, dated as of February 23, 2007.
4-C-3	8-K filed 8/3/10	4.1	Amendment No. 4, dated as of July 24, 2010, to Note Purchase Agreement, dated as of February 23, 2007.
4-D	8-K filed 8/23/07	4.1	Note Purchase Agreement, dated as of August 20, 2007.
4-D-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-D-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-D-3	8-K filed 7/01/09	4.2	Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007.
4-E	8-K filed 5/10/10	4.1	Second Amended and Restated Credit Agreement, dated as of May 4, 2010 between Otter Tail Corporation and the Banks named therein, U.S. Bank National Association, a national banking association, as administrative agent for the Banks and as Lead Arranger, Bank of America, N.A. and JPMorgan Chase Bank, National Association, as Co-Syndication Agents, and KeyBank National Association, as Documentation Agent.

	Previously Filed File No.	Previously Filed As Exhibit No.	
4-G	8-K filed 11/18/97	4-D-11	Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 between the registrant and U.S. Bank National Association (formerly First Trust National Association), as Trustee.
4-G-1	8-K filed 7/1/09	4.1	First Supplemental Indenture, dated as of July 1, 2009, to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997.
4-G-2	8-K filed 12/4/09	4.1	Officer's Certificate and Authentication Order, dated December 4, 2009, for the 9.000% Notes due 2016 (which includes the form of Note) issued pursuant to the Indenture (For Unsecured Debt Securities) dated as of November 1, 1997 and the First Supplemental Indenture thereto, dated as of July 1, 2009.
10-A	2-39794	4-C	Integrated Transmission Agreement, dated August 25, 1967, between Cooperative Power Association and the Company.
10-A-1	10-K for year ended 12/31/92	10-A-1	Amendment No. 1, dated as of September 6, 1979, to Integrated Transmission Agreement, dated as of August 25, 1967, between Cooperative Power Association and the Company.
10-A-2	10-K for year ended 12/31/92	10-A-2	Amendment No. 2, dated as of November 19, 1986, to Integrated Transmission Agreement between Cooperative Power Association and the Company.
10-C-1	2-55813	5-E	Contract dated July 1, 1958, between Central Power Electric Corporation, Inc., and the Company.
10-C-2	2-55813	5-E-1	Supplement Seven dated November 21, 1973. (Supplements Nos. One through Six have been superseded and are no longer in effect.)
10-C-3	2-55813	5-E-2	Amendment No. 1 dated December 19, 1973, to Supplement Seven.
10-C-4	10-K for year ended 12/31/91	10-C-4	Amendment No. 2 dated June 17, 1986, to Supplement Seven.
10-C-5	10-K for year ended 12/31/92	10-C-5	Amendment No. 3 dated June 18, 1992, to Supplement Seven.
10-C-6	10-K for year ended 12/31/93	10-C-6	Amendment No. 4 dated January 18, 1994 to Supplement Seven.
10-D	2-55813	5-F	Contract dated April 12, 1973, between the Bureau of Reclamation and the Company.
10-E-1	2-55813	5-G	Contract dated January 8, 1973, between East River Electric Power Cooperative and the Company.
10-E-2	2-62815	5-E-1	Supplement One dated February 20, 1978.
10-E-3	10-K for year ended 12/31/89	10-E-3	Supplement Two dated June 10, 1983.
10-E-4	10-K for year ended 12/31/90	10-E-4	Supplement Three dated June 6, 1985.
10-E-5	10-K for year ended 12/31/92	10-E-5	Supplement No. Four, dated as of September 10, 1986.
10-E-6	10-K for year ended 12/31/92	10-E-6	Supplement No. Five, dated as of January 7, 1993.
10-E-7	10-K for year ended 12/31/93	10-E-7	Supplement No. Six, dated as of December 2, 1993.
10-F	10-K for year ended 12/31/89	10-F	Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970).
10-F-1	10-K for year ended 12/31/89	10-F-1	Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-F-2	10-K for year ended 12/31/91	10-F-2	Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-F-3	10-K for year ended 12/31/91	10-F-3	Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-F-4	10-K for year ended 12/31/91	10-F-4	Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-F-5	10-Q for quarter ended 9/30/03	10.1	Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).

	PREVIOUSLY FILED		
	FILE NO.	AS EXHIBIT NO.	
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-1	10-Q for quarter ended 9/30/99	10	Power Sales Agreement between the Company and Manitoba Hydro Electric Board (dated as of July 1, 1999).
10-K	10-K for year ended 12/31/91	10-L	Integrated Transmission Agreement by and between the Company, Missouri Basin Municipal Power Agency and Western Minnesota Municipal Power Agency (dated as of March 31, 1986).
10-K-1	10-K for year ended 12/31/88	10-L-1	Amendment No. 1, dated as of December 28, 1988, to Integrated Transmission Agreement (dated as of March 31, 1986).
10-L	10-Q for quarter ended 06/30/04	10.1	Master Coal Purchase Agreement by and between the Company and Kennecott Coal Sales Company—Hoot Lake Plant (dated as of December 31, 2001).
10-M	8-K filed 7/01/09	10.1	Standstill Agreement, dated July 1, 2009, by and between the Registrant and Cascade Investment, L.L.C.
10-N-1	10-K for year ended 12/31/02	10-N-1	Deferred Compensation Plan for Directors, as amended.*
10-N-1a			First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10-N-2	8-K filed 02/04/05	10.1	Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-2a	10-K for year ended 12/31/06	10-N-2a	First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*

	PREVIOUSLY FILED		
	FILE NO.	AS EXHIBIT NO.	
10-N-2b			Second Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-3	10-K for year ended 12/31/93	10-N-5	Nonqualified Profit Sharing Plan.*
10-N-4	10-Q for quarter ended 3/31/02	10-B	Nonqualified Retirement Savings Plan, as amended.*
10-N-5	8-K filed 4/13/06	10.3	1999 Employee Stock Purchase Plan, As Amended (2006).
10-N-6	8-K filed 4/13/06	10.4	1999 Stock Incentive Plan, As Amended (2006).
10-N-7	10-K for year ended 12/31/05	10-N-7	Form of Stock Option Agreement.*
10-N-8	10-K for year ended 12/31/05	10-N-8	Form of Restricted Stock Agreement.*
10-N-9	8-K filed 4/13/06	10.2	Form of 2006 Performance Award Agreement.*
10-N-10	8-K filed 04/15/05	10.2	Executive Annual Incentive Plan (Effective April 1, 2005).*
10-N-11	10-Q for quarter ended 6/30/06	10.5	Form of 2006 Restricted Stock Unit Award Agreement.*
10-N-12	8-K filed 4/13/06	10.1	Form of Restricted Stock Award Agreement for Directors.
10-O	8-K filed 3/17/10	1.1	Distribution Agreement, dated March 17, 2010, between Otter Tail Corporation and J.P. Morgan Securities Inc.
10-P-1			Executive Employment Agreement, John Erickson.*
10-P-2			Executive Employment Agreement, Lauris Molbert.*
10-P-3			Executive Employment Agreement, Kevin Moug.*
10-P-4			Executive Employment Agreement, George Koeck.*
10-P-5			Executive Employment Agreement, Michelle Kommer.*
10-Q-1			Change in Control Severance Agreement, John D. Erickson.*
10-Q-2			Change in Control Severance Agreement, Lauris N. Molbert.*
10-Q-3			Change in Control Severance Agreement, Kevin G. Moug.*
10-Q-4			Change in Control Severance Agreement, George Koeck.*
10-Q-5			Change in Control Severance Agreement, Michelle L. Kommer.*
12.1			Calculation of Ratios of Earnings to Fixed Charges and Preferred Dividends.
21-A			Subsidiaries of Registrant.
23-A			Consent of Deloitte & Touche LLP.
24-A			Powers of Attorney.
31.1			Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2			Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2			Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS			XBRL Instance Document
101.SCH			XBRL Taxonomy Extension Schema Document
101.CAL			XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB			XBRL Taxonomy Extension Label Linkbase Document
101.PRE			XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF			XBRL Taxonomy Extension Definition Linkbase Document

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

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

SIGNATURES

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

OTTER TAIL CORPORATION

Dated: February 25, 2011

By /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer

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

Signature and Title	
John D. Erickson President and Chief Executive Officer (principal executive officer) and Director	
Kevin G. Moug Chief Financial Officer (principal financial and accounting officer)	
John C. MacFarlane Chairman of the Board and Director	By /s/ John D. Erickson John D. Erickson Pro Se and Attorney-in-Fact Dated February 25, 2011
Karen M. Bohn, Director	
Arvid R. Liebe, Director	
Edward J. McIntyre, Director	
Joyce Nelson Schuette, Director	
Nathan I. Partain, Director	
Gary J. Spies, Director	
James B. Stake, Director	

SHAREHOLDER SERVICES

OTTER TAIL CORPORATION STOCK LISTING

Otter Tail Corporation common stock trades on the NASDAQ Global Select Market. Our ticker symbol is OTTR. You can find our daily stock price on our web site, www.ottertail.com. Shareholders who sign up for Internet account access can view their account information online.

DIVIDENDS

Otter Tail Corporation has paid dividends on our common shares each quarter since 1938 without interruption or reduction. 2010 dividends were $1.19 per share and the year-end yield was 5.3%. Total shareholder return grew at a compounded average annual rate of 2.2% for the past 10 years.

DIVIDEND REINVESTMENT AND SHARE PLAN

The corporation's Dividend Reinvestment and Share Purchase Plan provides shareholders of record with a convenient method for purchasing shares of Otter Tail Corporation common stock. In addition, qualifying residents and customers of Otter Tail Power Company who are not shareholders of record are eligible to participate in the plan by enrolling with a minimum initial investment. About 80% of eligible shareowners holding about 13% of our eligible common shares are enrolled. Through this plan, participants may have their dividends automatically reinvested in additional shares without paying any brokerage fees or service charges. Shareholders also may contribute a minimum of $10 and a maximum of $10,000 per month. Automatic withdrawal from a checking or savings account is available for this service. Shareholders may sell up to 30 shares a month through the plan. For more information, contact Shareholder Services.

ELECTRONIC DIVIDEND DEPOSIT

Shareholders can arrange for electronic direct deposit of their dividends to their checking or savings accounts. Electronic deposit is safe, reliable and convenient. For authorization materials, contact Shareholder Services.

PROTECTING STOCK CERTIFICATES

Replacing missing certificates is a costly and time-consuming process so shareholders should keep a separate record of the certificate number, purchase date, date of issue, price paid and exact registration name. If you are enrolled in the Dividend Reinvestment and Share Purchase Plan, you have the option of depositing your common certificates into your plan account.

2011 CASH INVESTMENT AND SELL DATES FOR DIVIDEND REINVESTMENT

JAN. 3	FEB. 1	MAR. 1	APRIL 1	MAY 2	JUNE 1	JULY 1	AUG. 1	SEPT. 1	OCT. 3	NOV. 1	DEC. 1

TRANSFER AGENTS

Common and preferred:
Shareholder Services
Otter Tail Corporation
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: 800-664-1259 or 218-739-8479
Fax: 218-998-3165
Email: sharesvc@ottertail.com

Common only:
Shareowner Services
Wells Fargo Bank, N.A.
P.O. Box 64854
St. Paul, MN 55164-0854
Phone: 800-468-9716 or 651-450-4064

2011 DIVIDEND DATES

EX-DIVIDEND	RECORD	PAYMENT	
Feb. 11	Feb. 15	**P** Mar. 1	**C** Mar.10
May 11	May 13	**P** June 1	**C** June 10
Aug. 11	Aug. 15	**P** Sept. 1	**C** Sept. 10
Nov. 11	Nov. 15	**P** Dec. 1	**C** Dec. 10

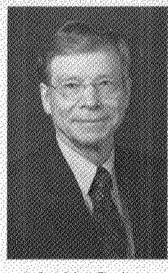
2011 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 11, 2011
10:00 a.m., Central Time
Bigwood Event Center
921 Western Avenue
Fergus Falls, Minnesota

KEY STATISTICS

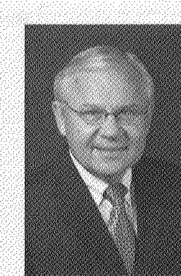
NASDAQ	OTTR
Senior unsecured debt ratings	
Otter Tail Corporation:	
Fitch	BBB-/stable
Moody's Investor Service	Baa3/stable
Standard & Poor's	BB+/stable
Otter Tail Power Company:	
Fitch	BBB+/stable
Moody's Investor Service	A3/stable
Standard & Poor's	BBB-/stable
Year-end stock price	$22.54
Year-end market-to-book ratio	1.3
Annual dividend yield	5.3%
Shares outstanding	36 million
Market capitalization (as of December 31, 2010)	$812 million
2010 average daily trading volume	154,331
Institutional holdings (shares as of December 31, 2010)	14.2 million

DIRECTORS

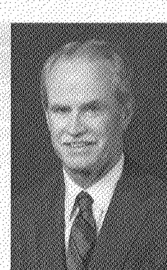

John MacFarlane


Karen Bohn

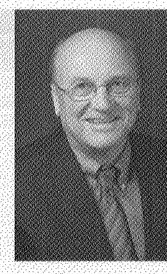

John Erickson


Arvid Liebe


Edward McIntyre


Nathan Partain


Joyce Schuette


Gary Spies


James Stake

JOHN C. MACFARLANE
Fergus Falls, Minnesota
Chairman of the Board of Directors, Retired President and Chief Executive Officer, Otter Tail Corporation

KAREN M. BOHN
*A/CG**, Edina, Minnesota
President, Galeo Group, LLC (management consulting firm)

JOHN D. ERICKSON
Fergus Falls, Minnesota
President and Chief Executive Officer, Otter Tail Corporation

ARVID R. LIEBE
C/CG, Milbank, South Dakota
Retired President, Liebe Drug, Inc. (retail business), Owner, Liebe Farms, Inc.

EDWARD J. MCINTYRE
A/C, White Salmon, Washington
Retired Vice President and Chief Financial Officer, Xcel Energy, Inc. (energy company)

NATHAN I. PARTAIN
A/C, Chicago, Illinois
President and Chief Investment Officer, Duff & Phelps Investment Management Co.; President, Chief Executive Officer and Chief Investment Officer, DNP Select Income Fund, Inc. (closed-end utility income fund)

JOYCE NELSON SCHUETTE
C/CG, Walker, Minnesota
Retired Managing Director and Investment Banker, Piper Jaffray & Co. (financial services)

GARY J. SPIES
A/CG, Fergus Falls, Minnesota
Chairman, Service Food, Inc. (retail business); Vice President, Fergus Falls Development Company and Midwest Regional Development Company, LLC (land and housing development)

JAMES B. STAKE
A/C, Edina, Minnesota
Retired Executive Vice President, Enterprise Services, 3M Company (diversified manufacturing)

**Committees: A-Audit C-Compensation CG-Corporate Governance*

EXECUTIVE AND SENIOR LEADERSHIP


Left to right: Paul Wilson, Stefan Nilsson, Charles MacFarlane, Kevin Moug, John Erickson, George Koeck, Michelle Kommer, Shane Waslaski, Michael Olsen

JOHN D. ERICKSON President & Chief Executive Officer
KEVIN G. MOUG Chief Financial Officer & Sr. Vice President
GEORGE A. KOECK General Counsel & Corporate Secretary, Sr. Vice President
MICHELLE L. KOMMER Sr. Vice President of Human Resources
MICHAEL J. OLSEN Sr. Vice President of Corporate Communications and Public Affairs
CHARLES S. MACFARLANE Sr. Vice President, Electric Platform
STEFAN K. NILSSON Sr. Vice President, Wind Energy Platform
SHANE N. WASLASKI Sr. Vice President, Manufacturing & Infrastructure Platform
PAUL J. WILSON Sr. Vice President, Health Services Platform

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