OTTER TAIL CORP
Form 10-K
February 27, 2009

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

þ **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2008

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

Commission File Number 0-368
OTTER TAIL CORPORATION
(Exact name of registrant as specified in its charter)

MINNESOTA	**41-0462685**
(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 þ No o)

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

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 þ No o)

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

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 30, 2008 was **$1,156,006,973.**

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date: **35,408,233 Common Shares ($5 par value) as of February 13, 2009.**

Documents Incorporated by Reference:

2008 Annual Report to Shareholders-Portions incorporated by reference into Parts I and II
Proxy Statement for the 2009 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 (the Company) to more accurately represent the broader scope of electric and nonelectric operations and the name Otter Tail Power Company was retained for use by the electric utility. 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. Information on the Company s website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

In the late 1980s, the Company determined its core electric business was located in a region of the country where there was little growth in the demand for electricity. In order to maintain growth for shareholders, the Company began to explore opportunities for the acquisition and long-term ownership of nonelectric businesses. This strategy has resulted in steady revenue growth over the years.

The Company s strategy is to continue to develop a core regulated electric utility combined with a diversified multi-industry platform. Reliable utility performance combined with growth opportunities at all its businesses provides long-term value. Growing the Company s core electric utility business provides a strong base of revenues, earnings and cash flows. The Company looks to its nonelectric operating companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. The Company expects much of its growth in the next few years will come from major capital investment at its existing companies. The Company also expects to grow through acquisition and adheres to strict guidelines when reviewing acquisition candidates. The Company s aim is to add companies that will produce an immediate positive impact on earnings and provide long-term growth potential. The Company believes that owning well-run, profitable companies across different industries will bring more growth opportunities and more balance to its results. In doing this, the Company also avoids concentrating business risk within a single industry. All of the Company s operating companies operate under a decentralized business model with disciplined corporate oversight.

The Company assesses the performance of its operating companies over time, using the following criteria:

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

The Company is a committed long-term owner, and therefore does not acquire companies in pursuit of short-term gains. However, the Company may divest operating companies that no longer fit into the Company s strategy over the long term.

Otter Tail Corporation and its subsidiaries conduct business in all 50 states and in international markets. The Company had approximately 4,166 full-time employees at December 31, 2008. The businesses of the Company have been classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

Electric (the Utility) includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company. In addition, the Utility is an active wholesale participant in the Midwest Independent Transmission System Operator (MISO) markets. The electric utility operations have been the Company s primary business since incorporation.

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

Manufacturing consists of businesses in the following manufacturing activities: production of wind towers, 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, Missouri, North Dakota, Oklahoma and Ontario, Canada and sell products primarily in 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 services and rental of diagnostic medical imaging equipment 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 25% of IPH s sales in 2008 were to customers outside of the United States.

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and four Canadian provinces.

The Company s corporate operating costs, which include corporate staff and overhead costs, the results of the Company s captive insurance company and other items, are excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets.

The Company s electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation, and the Company s energy services operation is operated as a subsidiary of Otter Tail Corporation. Substantially all of the other businesses are owned by the Company s wholly owned subsidiary, Varistar Corporation (Varistar).

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.

The Company continues to look for strategic acquisitions of additional businesses with emphasis on adding to existing operating companies and expects continued growth in this area.

On May 1, 2008 the Company s wholly owned subsidiary, BTD Manufacturing, Inc. (BTD), acquired the assets of Miller Welding & Iron Works, 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.

The Company made significant investments in its existing operating companies in 2008 in order to drive organic growth in the coming years. Capital expenditures exclusive of acquisitions totaled $266 million, including expenditures for the Utility s portion of the Langdon and Ashtabula Wind Energy Centers, and expansion of DMI Industries, Inc. s (DMI) wind tower manufacturing facilities in West Fargo, North Dakota and Tulsa, Oklahoma.

For a discussion of the Company s results of operations, see Management s Discussion and Analysis of Financial Condition and Results of Operations, which is incorporated by reference to pages 19 through 37 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

(b) <u>Financial Information About Industry Segments</u>

The Company is engaged in businesses that have been classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. Financial information about the Company s segments and geographic areas is incorporated by reference to note 2 of Notes to Consolidated Financial Statements on pages 49 through 51 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

(c) Narrative Description of Business

ELECTRIC

General

The Utility provides electricity to more than 129,000 customers in a 50,000 square mile area of Minnesota, North Dakota and South Dakota. The Company derived 26%, 26% and 28% of its consolidated operating revenues from the Electric segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively. The Company derived 95%, 45% and 48% of its consolidated income from continuing operations from the Electric segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively. The breakdown of retail revenues by state is as follows:

State	2008	2007
Minnesota	50.2%	49.7%
North Dakota	40.4	40.8
South Dakota	9.4	9.5
Total	100.0%	100.0%

The territory served by the Utility is predominantly agricultural. 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	2008	2007
Commercial	35.9%	36.3%
Residential	30.6	30.4
Industrial	23.1	23.1
All other sources	10.4	10.2
Total	100.0%	100.0%

Wholesale electric energy kilowatt-hour (kWh) sales were 38.7% of total kWh sales for 2008 and 28.6% for 2007. Wholesale electric energy kWh sales increased by 62.7% between the years while revenue per kWh increased by 3.0%. 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.

With the inception of the MISO Day 2 markets in April 2005, MISO introduced two new types of contracts, virtual transactions and Financial Transmission Rights (FTR). Virtual transactions are of two types: Virtual Demand Bid, which is a bid to purchase energy in MISO s Day-Ahead Market that is not backed by physical load, and Virtual Supply Offer, which is an offer submitted by a market participant in the Day-Ahead Market to sell energy not supported by a physical injection or reduction in withdrawals in commitment by a resource. An FTR is a financial contract that entitles its holder to a stream of payments, or charges, based on transmission congestion charges calculated in MISO s Day-Ahead Market. A market participant can acquire an FTR from several sources: the annual or monthly FTR auction, the FTR secondary market or a grant of an FTR in conjunction with a transmission service request. An FTR is structured to hedge a market participant s exposure to uncertain cash flows resulting from congestion of the transmission system. In 2008, net revenues from virtual and FTR transactions represented 0.3% of total electric energy revenues compared with 0.1% in 2007. As the MISO markets have evolved and become more efficient, profits from virtual transactions have declined.

The aggregate population of the Utility 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, 2008 the Utility served 129,268 customers.

Capability and Demand

As of December 31, 2008 and 2007 the Utility had owned net plant kilowatt (kW) capability as follows:

	2008	2007
Baseload plants		
Big Stone Plant	256,025 kW	256,025 kW
Coyote Station	149,450	149,450
Hoot Lake Plant	144,450	144,325
Total baseload net plant capability	549,925 kW	549,800 kW
Combustion turbine and small diesel units	131,045 kW	132,744 kW
Hydroelectric facilities	3,742 kW	4,338 kW
Owned wind facilities (rated at nameplate)		
Langdon Wind Center (27 turbines)	40,500 kW	
Ashtabula Wind Center (32 turbines)	48,000	
Total owned wind facilities	88,500 kW	

The baseload net plant capability for Big Stone Plant and Coyote Station constitutes the Utility s ownership percentages of 53.9% and 35%, respectively. The Utility owns 100% of the Hoot Lake Plant. During 2008, the Utility generated about 79% of its retail kWh sales and purchased the balance.

In addition to the owned facilities described above the Utility had the following purchase power agreements:

	2008	2007
Purchased wind agreements		
(rated at nameplate and greater than 2,000 kW)		
Edgeley	21,000 kW	21,000 kW
Langdon	19,500	
Total purchased wind	40,500 kW	21,000 kW
Purchased power agreements		
(in excess of 1 year and 500 kW)		
Manitoba Hydro	50,000 kW	50,000 kW
WAPA	5,500	5,500
Total purchased power	55,500 kW	55,500 kW

The Utility has a direct control load management system which provides some flexibility to the Utility to effect reductions of peak load. The Utility, in addition, offers rates to customers which encourage off-peak usage.

The Utility s participation in the 159 megawatt (MW) Langdon Wind Center south of Langdon, North Dakota includes the ownership of 27 wind turbines nameplate rated at 1.5 MW each and a 25-year power purchase agreement with Langdon Wind, LLC to purchase the electricity generated from 13 other wind turbines at the site. Construction of the 27 wind turbines owned by the Utility was completed in January 2008, adding approximately 8,100 kW of capacity to its net winter season generating capability and 6,075 kW of capacity to its net summer season generating capability.

In 2008, the Utility took ownership of 32 wind turbines at the 200 MW Ashtabula Wind Center under construction in Barnes County, North Dakota. The 32 wind turbines, nameplate rated at 1.5 MW each, became commercially operational in November 2008, adding approximately 9,600 kW of capacity to the Utility s net winter season generating capability and 7,200 kW of capacity to its net summer season generating capability.

The Utility traditionally experiences its peak system demand during the winter season. For the year ended December 31, 2008 the Utility experienced a system peak demand of 765,000 kW on December 22, 2008, which was also the highest all-time system peak demand (as reported to Mid-Continent Area Power Pool). Taking into account additional capacity available to it on December 22, 2008 under purchase power contracts (including short-term arrangements), as well as its own generating capacity, the Utility s capability of then meeting system demand, excluding reserve requirements computed in accordance with accepted industry practice, amounted to 959,660 kW (861,920 kW if reserve requirements are included). The Utility s additional capacity available under power purchase contracts (as described above), combined with generating capability and load management control capabilities, is expected to meet 2009 system demand, including industry reserve requirements.

Big Stone II

On June 30, 2005 the Utility 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. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant s nominal generating capacity from 630 MW to between 500 and 580 MW. New procedural schedules were established in the various project-related proceedings, which take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The Participation Agreement is an agreement to jointly develop, finance, construct, own (as tenants in common) and manage the Big Stone II Plant. The Participation Agreement includes provisions which obligate the parties to the agreement to obtain financing and pay their share of development, construction, operating and maintenance costs for the Big Stone II Plant. It also provides for the sharing of the plant output. Estimated construction costs for the plant including transmission are expected to be between \$1.5 billion and \$1.7 billion depending upon the size of unit constructed. The Participation Agreement provides that the Utility shall pay for and own approximately a 120 MW share of the Big Stone II Plant and be entitled to a corresponding interest in the plant s electrical output. The project participants included in the Participation Agreement a section covering withdrawal rights due to higher than anticipated project costs. Higher than anticipated project costs give each participant certain withdrawal rights exercisable at an agreed upon time. Under amendments to the Participation Agreement entered into in 2007, the agreed upon time has been extended to be 60 days after the later of receipt of the written Minnesota Public Utilities Commission (MPUC) Order regarding the Transmission Certificate of Need or receipt of a Prevention of Significant Deterioration (PSD) air permit from the South Dakota Board of Minerals and Environment. The Participation Agreement establishes a Coordinating Committee and an Engineering and Operating Committee to manage the development, design, construction, operation and maintenance of the Big Stone II Plant.

The Operation and Maintenance Agreement designates the Utility as the operator of the Big Stone II Plant. As operator, the Utility is required to provide staff and resources for the development, design, financing, construction and operation of the Big Stone II Plant. The other project participants are each required to reimburse the Utility for their respective share of the costs relating to those activities. The Coordinating Committee and the Engineering and Operating Committee, which are made up of representatives of all project participants, are authorized to supervise the Utility in its role as operator.

The Joint Facilities Agreement, which provided for the transfer of certain real property and easements from the Big Stone I Plant owners to the Big Stone II Plant participants and for the shared use of certain equipment and facilities between the two plants, terminated automatically on January 1, 2009 as a result of the project not reaching financial close. The Joint Facilities Agreement also allocated between the two plants the costs of operation and maintenance of the shared equipment and facilities. The Big Stone I Plant owners and Big Stone II Plant participants expect to put a new Joint Facilities Agreement in place during 2009.

The proposed project is intended to serve the participants native customer loads and is expected to be part of the Utility s regulated rate base. The project will be nominally rated between 500 and 580 MW, and it will be coal fired. The proposed project is expected to meet air emission requirements as prescribed by the Environmental Protection Agency (EPA) and the South Dakota Department of Environment and Natural Resources. Black & Veatch Corporation, a Kansas City based engineering firm, has been selected to do the plant design work and provide construction management services.

The participants have secured the permits required for construction and operation of the project, including the plant site permit, and are in the process of securing air quality permits and certificate of need and route permits for transmission. The federal Environmental Impact Statement (EIS) process led by the Western Area Power Administration (WAPA) continues to move forward. WAPA and its third party subcontractor continue to develop the Final EIS, which will include comments on the Draft EIS and the Supplemental Draft EIS, and responses to those comments. WAPA will develop a Record of Decision (ROD) following internal review and approval of the Final EIS. The Utility anticipates publication of the ROD in the Federal Register in the second quarter of 2009.

For more information regarding the status of the permitting process of the Big Stone II project, see General Regulation and Environmental Regulation.

Whether Big Stone II is completed will depend on how the conditions are ultimately written in the Certificate of Need order by the MPUC, if the EIS permit is obtained, if financing can be obtained and whether or not shareholders of the Company will be given an opportunity for reasonable returns.

Financial close, which requires the participants to provide binding financial commitments to support their share of costs, is to occur 90 days after the EIS ROD.

As of December 31, 2008 the Utility capitalized $11.6 million in costs related to the planned construction of Big Stone II. If the project is abandoned for permitting or other reasons, a portion of these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

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 the Utility s net output of electricity for 2008 and 2007:

	2008		2007	
Sources	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated	Net Kilowatt Hours Generated (Thousands)	% of Total Kilowatt Hours Generated
Subbituminous Coal	2,613,060	67.7%	2,273,799	67.1%
Lignite Coal	1,016,828	26.4	1,032,449	30.5
Hydro and Renewables	177,250	4.6	20,537	.6
Natural Gas and Oil	48,957	1.3	59,256	1.8
Total	3,856,095	100.0%	3,386,041	100.0%

The Utility has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Kennecott Coal Sales Company	Wyoming subbituminous	December 31, 2010
Hoot Lake Plant	Kennecott Coal Sales Company	Wyoming subbituminous	December 31, 2010
Coyote Station	Dakota Westmoreland Corporation	North Dakota lignite	May 4, 2016

The contract with Dakota Westmoreland Corporation has a 5 to 15-year renewal option subject to certain contingencies. It is the Utility 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 Unit for each of the three years 2008, 2007 and 2006 was $1.678, $1.486 and $1.419, respectively.

The Utility is permitted by the State of South Dakota to burn some alternative fuels, including tire-derived fuel and biomass, at the Big Stone Plant.

General Regulation

The Utility 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:

		2008		2007	
Rates	Regulation	% of Electric Revenues	% of kWh Sales	% of Electric Revenues	% of kWh Sales
MN retail sales	MN Public Utilities Commission	32.6%	31.7%	37.1%	34.5%
ND retail sales	ND Public Service Commission	26.3	23.4	30.4	25.8
SD retail sales	SD Public Utilities Commission	6.1	6.2	7.1	6.4
Transmission & wholesale	Federal Energy Regulatory Commission	35.0	38.7	25.4	33.3
		100.0%	100.0%	100.0%	100.0%

The Utility operates under approved retail electric tariffs in all three states it serves. The Utility has an obligation to serve any customer requesting service within its assigned service territory. Accordingly, the Utility has designed its electric system to provide continuous service at times of peak usage. The pattern of electric usage can vary dramatically during a 24-hour period and from season to season. The Utility s tariffs provide for continuous electric service and are designed to cover the costs of service during peak times. 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, the Utility has approved tariffs in all three states for lower rates for residential demand control, 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 the Utility resources, while giving customers more control over the size of their electric bill. In all three states, the Utility has approved tariffs which allow qualifying customers to release and sell energy back to the Utility when wholesale energy prices make such transactions desirable.

The majority of the Utility s electric retail rate schedules now in effect provide for adjustments in rates based on the cost of fuel delivered to the Utility s generating plants, as well as for adjustments based on the cost of electric energy purchased by the Utility. Such adjustments are presently based on a two-month moving average in Minnesota and by the Federal Energy Regulatory Commission (FERC), a three-month moving average in South Dakota and a four-month moving average in North Dakota. These adjustments are applied to the next billing period after becoming applicable.

The following summarizes the material regulations of each jurisdiction applicable to the Utility 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, the Utility 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 MNDOC 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 MNDOC also has the power, in the event of energy shortage or for a long-term basis, to prepare and adopt regulations to conserve and allocate energy.

In an order issued by the MPUC on August 1, 2008 the Utility was granted an increase in Minnesota retail electric rates of $3.8 million or approximately 2.9%, compared with the originally requested increase of approximately 6.7%. An interim rate increase of 5.4% went into effect on November 30, 2007. The Utility will refund Minnesota customers the difference between interim rates and final rates, with interest, in March 2009. Amounts refundable totaling $3.9 million have been recorded as a liability on the Company s consolidated balance sheet as of December 31, 2008. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. The Utility deferred recognition of $1.5 million in rate case-related filing and administrative costs in June 2008 that are subject to amortization and recovery over three years under new rates as ordered by the MPUC. As a result of an MPUC decision on reconsideration of the treatment of profit margins on the resale of electricity purchased from other companies, the Utility will assign an amount of its costs to this unregulated activity but will not be required to credit any portion of nonasset-based margins to retail customers.

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. The Utility 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. Since 1995, the Utility has recovered 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.

Minnesota law requires utilities to submit to the MPUC for approval a 15-year advance integrated resource plan (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 hearings, rate reviews and other proceedings. Typically, the filings are submitted every two years. The Utility submitted its most recent IRP on July 1, 2005. On June 5, 2008 the MPUC deferred approval of the Utility s 2006-2020 IRP. The addition of 160 MW of wind generation in the IRP was approved early in 2007 and, on January 15, 2009, the MPUC approved the Utility s 2006-2020 IRP in its entirety. As of the date of this report, the MPUC had not issued a written order reflecting its decision. This 2006-2020 IRP includes new renewable wind generation and significant demand-side management, including conservation, new baseload including the proposed Big Stone II power plant, natural gas-fired peaking plants and wholesale energy purchases. The delays in approval of the Big Stone II transmission Certificate of Need in Minnesota and issuance of required permits may delay the availability of Big Stone II as a generation resource. Also the Utility has experienced more rapid load growth than was expected since originally filing the IRP in 2005. The Utility is assessing ways in which to address this potential near-term generation shortfall and has requested authority from the MPUC to immediately acquire up to 110 MW of peaking capacity. The MPUC committed to expediting a decision on this request. The Utility will be required to file its next IRP before the end of 2009.

The Minnesota legislature has enacted a statute that favors conservation over the addition of new resources. In addition, it has mandated 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 resource plans. 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.

In February 2007, the Minnesota legislature passed a renewable energy standard requiring the Utility 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. The Utility has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. By the end of 2010, the Utility expects to have sufficient renewable energy resources available to comply with the required 2012 level of the Minnesota renewable energy standard. The Utility 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 standards. The MPUC is now 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 now 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 the Utility s proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in renewable energy facilities. The rider enables the Utility to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Renewable Resource Adjustment of 0.19 cents per kWh was included on Minnesota customers electric service statements beginning in September 2008. The first renewable energy project for which the Utility will receive cost recovery is its 40.5 MW ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The Utility has recognized a regulatory asset of $3.0 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of December 31, 2008.

The Utility is awaiting a decision from the MPUC on its 2009 Rider Adjustment filing with an expected implementation date of April 1, 2009. The 2009 Rider Adjustment filing includes a request for recovery of the Utility s investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008.

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 electric transmission facilities. The MPUC may approve a tariff rider to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need proceeding or certified by the MPUC as a Minnesota priority transmission project or investment and expenditures made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility s retail customers. Such transmission cost recovery riders would allow a return on investments at the level approved in a utility s last general rate case. The Utility expects to file a proposed rider with the MPUC to recover its share of costs of eligible transmission infrastructure upgrades projects in 2009.

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 Law 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 Utility and a coalition of six other electric providers filed an application for a Certificate of Need 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 Certificate of Need and Route Permit for the Minnesota portion of the Big Stone II transmission line. The motion involved numerous elements, including the following:

That there is reasonable assurance that Big Stone II would be more cost-effective than renewable energy beyond the statutory levels of renewable energy based on accepted estimates of construction costs and carbon dioxide (CO_2);

That the 345 kV transmission project is necessary based on identified regional and state transmission needs; and

That the project presents risks requiring additional measures to protect the applicants ratepayers.

Therefore, the MPUC determined to grant the Certificate of Need subject to a number of additional conditions pending issuance of a final order, 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/kilowatt and CO_2 costs at $26/ton.

The Certificate of Need and Route Permit are required by state law and would allow 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.

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. This legislation also transferred environmental review authority from the Environmental Quality Board to the MNDOC.

Planning studies have shown there will be significant electric load growth and more transmission will be necessary for renewable energy in the coming decade. This led to a joint transmission planning initiative among eleven utilities that own transmission lines in Minnesota and the surrounding region, called CapX 2020 capacity expansion by 2020. On August 16, 2007 the eleven CapX 2020 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. Evidentiary hearings for the Certificate of Need for the three CapX 2020 345-kV transmission line projects began in July 2008 and continued into August 2008. The MPUC is expected to decide if the lines meet regulatory need requirements by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are completed (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading these projects, and the Utility and eight other utilities are involved in permitting, building and financing. The Utility is directly involved in two of these three projects and serves as the lead utility in a fourth Group 1 project, the Bemidji-Grand Rapids 230-kV line which has an expected in-service date of 2012-2013.

The Utility filed a Certificate of Need for the fourth project on March 17, 2008. The MNOES staff completed briefing papers regarding the Bemidji-Grand Rapids route permit application. The MNOES staff recommended to the MPUC: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the Certificate of Need and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the MNOES staff recommendation. The MPUC agreed the Certificate of Need and route permit applications were complete. The commissioners asked the CapX 2020 utilities to add a section to the Certificate of Need application addressing how the new Minnesota Conservation Improvement Programs (CIP) statutes will affect the need for the project. Because no one has intervened in the Certificate of Need proceeding, the MPUC will handle the Certificate of Need application as an uncontested case. The MNOES subsequently recommended that need for the line has been established. The MPUC is expected to determine if there is a need for this line and, if appropriate, issue the route permit in spring 2010. The Utility s 2009 2013 capital budgets include $66 million for CapX 2020 expenditures.

In December 2005, the MPUC issued an order denying the Utility s request to allow recovery of certain MISO-related costs through the fuel clause adjustment (FCA) in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The Utility recorded a $1.9 million reduction in revenue and a refund payable in December 2005 to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The MPUC s final order was issued on February 24, 2006 requiring jurisdictional investor-owned utilities in the state to participate with the MNDOC and other parties in a proceeding that would evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The February 24, 2006 order eliminated the refund provision from the December 2005 order and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the utility s next general rate case. As a result, the Utility recognized $1.9 million in revenue and reversed the refund payable in February 2006. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006.

In an order issued on December 20, 2006 the MPUC stated that except for schedule 16 and 17 administrative costs, discussed below, each petitioning utility may recover the charges imposed by the

MISO for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of the utility s FCA from the period April 1, 2005 through a period of at least three years after the date of the order. The MPUC also ordered the utilities to refund schedule 16 and 17 costs collected through the FCA since the inception of MISO Day 2 Markets in April 2005 and stated that each petitioning utility may use deferred accounting for MISO schedule 16 and 17 costs incurred since April 1, 2005. This deferred accounting may continue for ongoing schedule 16 and 17 costs, without the accumulation of interest, until the earlier of March 1, 2009 or the utility s next electric rate case. Pursuant to this December 20, 2006 order, the Utility was ordered to refund $446,000 in MISO schedule 16 and 17 costs to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007. The Utility requested recovery of the deferred costs and recovery of the ongoing costs in its general rate case filed in October 2007 and, in January 2008, began amortizing $855,000 of deferred MISO schedule 16 and 17 costs over a 35-month period. The August 1, 2008 MPUC Order in the general rate case allowed future recovery of MISO schedule 16 and 17 costs and recovery of the deferred schedule 16 and 17 costs.

The MNDOC and the Utility identified two operational situations which are not covered in the approved method for allocating MISO costs contained in the final December 20, 2006 MPUC order discussed above. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is related to Financial Transmission Rights not needed for retail load. For the period July 1, 2005 through June 30, 2007, the Utility determined its Minnesota customers portion of costs associated with these situations to be $765,000. The data was provided to the MNDOC during the course of the MNDOC s review of the Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report). The Utility offered to refund $765,000 to its Minnesota customers to settle this and other issues raised by the MNDOC in the AAA Report docket before the MPUC and the MNDOC accepted the offer in October 2007 and recommended that the MPUC include the refund in its final order. The Utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC s December 20, 2006 order. The Utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the Utility s refund offer and modifications and closed this docket on February 6, 2008. In December 2007, the Utility recorded a liability and a reduction to revenue of $805,000 for the amount of the refund offer and similar revenues collected subsequent to June 30, 2007. Refunds to Minnesota customers were completed during 2008.

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 the Company. Once the petition is approved, the Company may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved capital structure petition. The Company s current capital structure petition is in effect until the MPUC issues a new capital structure order for 2009. The Company expects to file its 2009 capital structure petition in April and expects to receive approval from the MPUC prior to August 31, 2009.

In September 2004 the Company provided a letter to the MPUC summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the Utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The Utility filed these documents with the MPUC in the second quarter of 2006. Subsequently, at a MPUC hearing on January 25, 2007 all remaining open issues were resolved. On two of the issues resolved, the MPUC required the Utility to include all of the Company s short-term debt in its calculations of allowance for funds used during construction (AFUDC) and the Utility agreed to provide the MPUC the results of the ongoing FERC operational audit when available. The Company recorded a noncash charge of $3.3 million in 2006 related to the disallowance of a portion of capitalized AFUDC from the Utility s rate base as a result of including all of the Company s short-term debt, regardless of use, in the Utility s calculation of AFUDC. On December 12, 2007, the MPUC issued its order closing the investigation subject to the Company s continuing responsibility to file the report on its FERC operational audit as soon as available and subject to any further development of the record required in the Utility s recent general rate case. FERC Order (IN08-6-000), resolving alleged network transmission service violations by the Utility of the Open Access Transmission and Energy Markets Tariff of the MISO was issued on May 29, 2008 and filed with the MPUC on June 4, 2008.

North Dakota: The Utility 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 the Utility. 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 of 100,000 kW or more and proposed new transmission lines of more than 115 kV. The Utility 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 Securities and Exchange Commission is expressly exempted from review by the NDPSC under North Dakota state law.

On November 3, 2008 the Utility 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, to begin on January 2, 2009, of approximately 4.1%, or $4.8 million annualized. A final decision by the NDPSC on the Utility s request is expected by August 1, 2009. Interim rates will remain in effect for all North Dakota customers until the NDPSC makes a final determination on the Utility s request. If final rates are lower than interim rates, the Utility will refund North Dakota customers the difference with interest.

On May 21, 2008 the NDPSC approved the Utility s request for a Renewable Resource Cost Recovery Rider to enable the Utility to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The Renewable Resource Cost Recovery Rider Adjustment of 0.193 cents per kWh was included on North Dakota customers electric service statements beginning in June 2008. The first renewable energy project for which the Utility will receive cost recovery is its 40.5 MW ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The Utility may also recover through this rider costs associated with other new renewable energy projects as they are completed. The Utility has 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 Renewable Resource Cost Recovery Rider Adjustment. A Renewable Resource Cost Recovery Rider Adjustment rate of 0.51 cents per kWh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009.

The Utility had not been deferring recognition of its renewable resource costs eligible for recovery under the North Dakota Renewable Resource Cost Recovery Rider but had been charging those costs to operating expense since January 2008. After approval of the rider, the Utility accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider. The Company s December 31, 2008 consolidated balance sheet includes a regulatory asset of $2.0 million for revenues that are eligible for recovery through the North Dakota Renewable Resource Cost Recovery Rider but that had not been billed to North Dakota customers as of December 31, 2008.

North Dakota legislation also 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. However, the Utility has requested recovery of such costs in its general rate case filed in November 2008.

In February 2005, the Utility filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the FCA. The NDPSC granted interim recovery through the FCA in April 2005, but similar to the decision of the MPUC, 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 the Utility and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, the Utility 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. The Utility 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. As of December 31, 2008 the Utility had deferred $823,000 in MISO schedule 16 and 17 costs in North Dakota, which it will amortize over 36 months beginning in January 2009 in conjunction with the implementation of interim rates in North Dakota. Request for approval of base rate recovery for deferred and on-going MISO schedule 16 and 17 costs are included in the pending general rate case.

A filing in North Dakota for an advance determination of prudence of Big Stone II was made by the Utility in November 2006. Evidentiary hearings were held in June 2007. The NDPSC decision was delayed because of the change in ownership of the project. On August 27, 2008, the NDPSC determined that the Utility s participation in Big Stone II was prudent in a range of 121.8 to 130 MW. The NDPSC decision has been appealed to Burleigh County District Court by interveners in the matter. In addition, the NDPSC ordered the Utility to file, for approval, proposals to implement demand-side management and conservation programs identified as more economic resources than Big Stone II. This filing was submitted in February 2009.

South Dakota: Under the South Dakota Public Utilities Act, the Utility is subject to the jurisdiction of the SDPUC with respect to rates, public utility services, establishment of assigned service areas and other matters. The Utility 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 of 115 kV or more.

On October 31, 2008 the Utility filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which provides for recovery of renewable resource investments and expenses in base rates. South Dakota rules do not provide for interim rate increases pending approval of final rates. A final decision by the SDPUC on the Utility s request is expected in mid-summer 2009. Prior to this general rate case there have been no significant rate proceedings in South Dakota since November 1987.

The Utility and a coalition of six other electric providers filed an Energy Conversion Facility Siting Permit Application for Big Stone II with the SDPUC on July 21, 2005. The permit was granted by the SDPUC on July 14, 2006 but was appealed by a group of interveners on the basis that CO_2 concerns had not been adequately addressed. In February 2007 a South Dakota circuit court judge issued an opinion affirming the decision of the SDPUC to grant the siting permit for Big Stone II. The permit was appealed to the South Dakota Supreme Court. On January 16, 2008 the South Dakota Supreme Court unanimously affirmed the SDPUC s decision to grant Big Stone II project participants a site permit. A permit application for the South Dakota portion of the transmission line for Big Stone II was filed with the SDPUC on January 16, 2006 and was approved by the SDPUC on January 2, 2007.

On November 20, 2008 the South Dakota Board of Minerals and Environment unanimously approved the Big Stone II participating utilities application for a Prevention of Significant Deterioration (PSD) permit for Big Stone II and a proposed Title V Operating Permit for the Big Stone site. A PSD permit is a pre-construction permit designed to protect air quality. Joint petitioners Sierra Club and Clean Water Action have appealed the administrative decision on the PSD permit to the Circuit Court of Hughes

County. The appeal is currently pending before the court. The issuance of the Title V permit is subject to review by the U.S. Environmental Protection Agency (EPA). On January 22, 2009, the EPA filed a formal objection to the proposed Title V permit. The State of South Dakota has revised and submitted a proposed permit in response to the EPA s objection.

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 the Utility 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.

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 April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time revenue sufficiency guarantee (RSG) charges that were not allocated to day-ahead virtual supply offers in accordance with MISO s Open Access Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006 the FERC issued a Notice of Extension of Time, permitting MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of the compliance filing. On October 26, 2006 the FERC issued an order on rehearing of the April 25, 2006 order, stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO s TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 26, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order s waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007 the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the MISO s April 17, 2007 RSG compliance filing to comply with the FERC s March 15, 2007 RSG order. The compliance order reinserted language requiring the actual withdrawal of energy by market participants, restored the MISO s original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions. The second related RSG order issued by FERC on November 5, 2007 was its order on rehearing on its April 25, 2006 order, in which it rejected the MISO s proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG second rehearing order (the Utility was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG compliance order.

In the RSG compliance order, the FERC rejected the MISO s proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently effective tariff, which allocates RSG costs to virtual supply offers, remains in effect. In the RSG second rehearing order, the FERC clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The Utility recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO s interpretation of the order on rehearing, the Utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the Utility. Accordingly, the Utility revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007.

On March 15, 2007 the FERC also directed MISO to make another compliance filing that the FERC addressed on November 7, 2008 (RSG Compliance Order III). In RSG Compliance Order III, the FERC concluded that its interpretation in RSG III regarding the RSG rate denominator was in error and that a different interpretation applied. On November 10, 2008 the FERC issued an order on the paper hearing finding the current RSG rate unjust and unreasonable and accepting an interim rate that applied RSG charges to all virtual sales until such time that MISO makes a subsequent filing of the new RSG rate. In response to RSG Compliance Order III, MISO made another compliance filing on December 8, 2008 in which it proposed to re-resettle the RSG charges and cost allocations back to market start to correct its previous resettlement completed in January 2008 that was based on the FERC s interpretation of the RSG rate and billing determinants affirmed in RSG III. In addition to correcting the RSG rate denominator to limit it to only virtual sales associated with actual physical energy withdrawals, MISO proposed additional corrections designed to reduce the denominator. Both changes will increase the RSG rate that the Utility must pay. Also, on November 11, 2008 the FERC issued an order on rehearing of the November 28, 2007 order on complaint. Again, where the revenue from RSG charges collected is not sufficient to make RSG payments to suppliers, MISO recovers the shortage through an uplift charge from all load.

The Utility requested rehearing of both November 10, 2008 orders (in conjunction with the FERC s RSG Compliance Order III). If the FERC denies rehearing, the Utility will likely seek review at the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The Utility s principal concern in these proceedings was to ensure that the FERC did not impose refunds prior to the August 10, 2007 refund effective date. The FERC did not impose such refunds but did offer an interpretation in support of its decision in RSG Compliance Order III (in ER04-691 docket) that would subject the Utility to further RSG refunds and resettlements prior to August 10, 2007.

Since 2006, the Utility has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdraw energy from the market or engage 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 D.C. Circuit. These proceedings create potential contingent liabilities in three separate periods for the Utility: (1) April 1, 2005 through April 24, 2006; (2) April 25, 2006 through August 9, 2007; and (3) August 10, 2007 forward. The Utility identified and assessed potential contingent RSG liabilities under various scenarios depending on the time period over which the FERC ultimately orders RSG refunds. The Utility accrued a liability in 2008 based on the outcome it determined to be most probable. The Company does not know when these litigation proceedings will conclude.

The FERC s Office of Enforcement, formerly referred to as the Division of Audits of the Office of Market Oversight and Investigations, commenced an audit in 2005 of the Utility s transmission practices for the period January 1, 2003 through August 31, 2005. The purpose of the audit was to determine whether the

Utility s transmission practices were in compliance with the FERC s applicable rules, regulations and tariff requirements and whether the implementation of the Utility s waivers from the requirements of Order No. 889 and Order No. 2004 appropriately restricted access to transmission information that would benefit the Utility s off-system sales. FERC staff identified two of the Utility s transmission practices that it believed were out of compliance. The Utility believes its actions were in compliance with the MISO tariff but rather than litigate, it entered into a Stipulated Settlement Agreement with FERC staff resolving all issues related to the audit. The FERC approved the settlement agreement on May 29, 2008 and issued FERC Order (IN08-6-000) which resolved alleged network transmission service violations by the Utility of MISO s TEMT. The Utility agreed to pay $547,000 plus interest of $141,000 to the Low Income Home Energy Assistance Program administered by the three states served by the Utility. This amount represents profits earned by the Utility on transactions FERC staff believes incorrectly utilized network transmission service under MISO s TEMT. Enforcement staff did not seek to impose a compliance monitoring plan on the Utility because the MISO s Day 2 market is now operational and its member utilities no longer schedule transmission within the system.

The Comprehensive Energy Policy Act of 2005 (the 2005 Energy Act), signed into law in August 2005, substantially affected the regulation of energy companies, including the Utility. The 2005 Energy Act amended federal energy laws and provided the FERC with new oversight responsibilities. Among the important changes implemented as a result of this legislation were the following:

The Public Utility Holding Company Act of 1935 (PUHCA) was repealed effective February 8, 2006. PUHCA significantly restricted mergers and acquisitions in the electric utility sector.

FERC appointed the Electric Reliability Organization (ERO) formerly known as North American Electric Reliability Council (NERC) as an electric reliability organization to establish and enforce mandatory reliability rules regarding the interstate electric transmission system. On January 1, 2007 the ERO began operating.

The FERC established incentives for transmission companies, such as performance based rates, recovery of costs to comply with reliability rules and accelerated depreciation for investments in transmission infrastructure.

Federal support was made available for certain clean coal power initiatives, nuclear power projects and renewable energy technologies.

MEMA: The Utility 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: The Utility is a member of the Midwest Reliability Organization (MRO). The MRO, a non-profit organization that replaced the MAPP Regional Reliability Council, is one of eight Regional Reliability Councils that comprise the NERC. The MRO operates to ensure the reliability of the bulk power system in the Midwest part of North America. The MRO, through its balanced stakeholder board with independent oversight, operates independently from any member, market participant or operator, so that the standards developed and enforced by the MRO are fair and administered without undue influence from market participants. The MRO is approximately 40% larger in terms of net end use load than MAPP. The MRO region includes more than 40 members supplying approximately 280 million mWh to more than 20 million people. Its membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations and independent power producers.

MISO: The Utility is a member of the MISO. As expressed in FERC Order No. 2000, FERC s view is that independent regional transmission organizations will benefit the public interest by enhancing

the reliability of the electric grid and providing unbiased regional grid management, nondiscriminatory operation of the bulk power transmission system and open access to the transmission facilities under MISO s functional supervision. The MISO covers a broad region containing all or parts of 20 states and one Canadian province. The MISO began operational control of the Utility s transmission facilities above 100 kV on February 1, 2002 but the Utility continues to own and maintain its transmission assets. 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 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. The Utility has actively participated in the market since its commencement.

In December 2008 the Utility sent MISO a letter of intent to withdraw from MISO. This procedural step was taken to allow the Utility the opportunity to withdraw from MISO at the end of 2009 if concerns about MISO charges born by retail customers cannot be resolved. Withdrawal from MISO would require the Utility to secure replacement of MISO-provided services from other sources.

MAPP: The Utility has been a participant in the MAPP generation reserve sharing pool, which operates in parts of eight states in the Upper Midwest and in three provinces in Canada. As a result of the start up of the ASM, the Utility is withdrawing from the generation reserve sharing pool of MAPP. The MAPP generation reserve sharing pool provided for, among other things, the contingency reserves necessary to meet certain major events such as the loss of a large generating unit or a transmission line.

Other: The Utility 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 2005 Energy Act described above.

Holding Company Reorganization

The Company s Board of Directors has authorized a holding company reorganization of the Company s regulated utility business. Following the completion of the holding company reorganization, Otter Tail Power Company, which is currently operated as a division of Otter Tail Corporation, will be operated as a wholly owned subsidiary of the new parent holding company to be named Otter Tail Corporation. In connection with the reorganization, each outstanding Otter Tail Corporation common share will be automatically converted into one common share of the new holding company, and each outstanding Otter Tail Corporation cumulative preferred share will be automatically converted into one cumulative preferred share of the new holding company having the same terms. The holding company reorganization is subject to approval by Minnesota, North Dakota and South Dakota regulatory agencies and by the FERC, consents from various third parties and certain other conditions. In an order issued on August 18, 2008, the FERC authorized the reorganization subject to certain conditions specified in the order. In an order issued on October 10, 2008, the NDPSC approved the Company s application to form a holding company. In a meeting held on October 30, 2008, the SDPUC approved the Company s application to form a new holding company. The MPUC approved the Company s request to form a holding company with certain conditions at its hearing on December 11, 2008. There remain several business and legal steps that must be accomplished before the reorganization can be completed.

Competition, Deregulation and Legislation

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

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

Legislative and regulatory activity could affect operations in the future. The Utility cannot predict the timing or substance of any future legislation or regulation. There has been no legislative action regarding electric retail choice in any of the states where the Utility operates. The Minnesota legislature has in the past, and again is, considering legislation which would regulate holding companies doing business within the state that include in the ownership chain a public utility. Proposed legislation would foreclose public utilities, or holding companies of which public utilities are members, from acquiring an interest in a company that is not a public utility or that does not receive 50 percent or more of its revenue from electric or gas utility-related business. This legislation, if passed in its present form, could limit the Company s ability to maintain and grow its nonelectric businesses. The Company does not expect retail competition to come to the States of Minnesota, North Dakota or South Dakota in the foreseeable future.

Some of the Company s businesses could benefit from renewable energy development incentives included in the American Recovery and Reinvestment Act of 2009 recently passed by Congress.

The Utility 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: The Utility 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, 2008 the Utility invested approximately $17.4 million in environmental control facilities. The 2009 construction budget includes approximately $0.6 million for environmental equipment for existing facilities. The Utility s share of environmental expenditures for the proposed Big Stone II Plant is estimated to be $133 million, including the cost of a joint scrubber, which will be shared between the current Big Stone Plant and the proposed Big Stone II Plant.

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

The primary fuels burned by the Utility 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. The Utility 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, the Utility believes the units at the Hoot Lake Plant currently meet all presently applicable federal and state air quality and emission standards.

During the fall of 2007 maintenance outage at the Big Stone Plant, the demonstration project Advanced Hybrid technology was replaced with a pulse jet baghouse. 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 Act, 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 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 the Utility 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. Hoot Lake Plant unit 2 was governed by the phase one early opt-in provision until January 1, 2008. In order to meet the national NO_x emission standards required at the Hoot Lake Plant unit 2 in 2008, the Utility 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 the NO_x emission regulations that were adopted by the EPA in December 1996. All of the Utility s generating facilities met the NO_x standards during 2008.

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 ($PM_{2.5}$). The EPA also concluded that NO_x emissions are the chief emissions contributing to ozone non-attainment. Twenty-three states and the District of Columbia were found to contribute to ambient air quality $PM_{2.5}$ non-attainment 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 for emissions caps. Twenty-five states were found to contribute to downwind 8-hour ozone non-attainment. None of the states in the Utility s service territory were slated for NO_x reduction for ambient air quality 8-hour ozone non-attainment 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 without vacatur for the EPA to conduct further proceedings consistent with the court s prior opinion. The court did not impose a definitive deadline by which the EPA must correct CAIR. On January 16, 2009, the EPA proposed a rule that would stay the effectiveness of CAIR and the CAIR federal implementation plan for sources in Minnesota while the EPA 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. Given the uncertainty of the proposed rule, future EPA action and whether Minnesota will be included in the CAIR, the impact on Otter Tail facilities is uncertain at this time. Nonetheless, NO_x emissions control equipment has been installed on Hoot Lake Plant unit 2 as described above, and was installed on unit 3 in 2007 in anticipation of having to meet CAIR requirements.

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. Hoot Lake Plant unit 3 and Big Stone Plant are units that are potentially subject to emission reduction requirements. The Minnesota Pollution Control Agency (MPCA) has determined that Hoot Lake Plant unit 3 is not subject to the BART rule. A similar determination has not been made for Big Stone Plant and it remains potentially subject to emission reduction requirements. At the request of the South Dakota Department of Environment and Natural Resources (DENR), the Utility agreed to model Big Stone emissions to evaluate the impact of plant emissions on Class I air quality areas. The modeling effort was completed and the final report submitted to the DENR on March 19, 2008. Although the DENR has not as yet acted on the report, the report concluded that Big Stone does not contribute to visibility impairment in Class I air quality areas and is exempt from the BART process. The Utility has responded to questions and comments posed by the reviewing agencies and has provided a revised modeling protocol for consideration by the DENR, the EPA and the Federal Land Managers. The state rule revisions were due by January 2008, but South Dakota rule revisions have been delayed. Given the regulatory uncertainties at this time, it is not possible to assess to what extent this regulation will impact the Utility.

The Act calls for EPA studies of the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and submitted reports to Congress. The Act 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. The EPA published the proposed mercury rule on January 30, 2004. The proposal included two options for regulating mercury emission from coal-fired electric generating units. One option would set technology-based maximum achievable control technology standards under paragraph 111(d) of the Act. The other option embodied a market-based cap and trade approach to emissions reduction. The EPA published final rules in May 2005 based on the cap and trade approach. On October 28, 2005 the EPA announced a reconsideration of portions of the final rules. Final rules were published on June 9, 2006 that maintained the cap and trade approach. On February 8, 2008, the United States Court of Appeals for the D.C. Circuit granted petitions for review of the EPA rules and vacated the rules that would have allowed the EPA to regulate mercury emissions based on a cap and trade approach. 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. EPA rulemaking is slated to proceed under the maximum achievable control technologies (MACT) provision of the Clean Air Act section 112(d) for existing units and section 112(g) case-by-case MACT provisions for affected new units. Given the potential for legal challenges and regulatory uncertainties associated with the EPA s revised rulemaking, it is not possible to assess to what extent the court s recent decision will impact the Utility.

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 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 Act by making major modifications to their facilities without installing state-of-the-art pollution controls. On January 2, 2001 the Utility received a request from the EPA, pursuant to Section 114(a) of the Act, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. The Utility 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, the Utility received another request from EPA Regions 5 and 8, pursuant to Section 114(a) of the Act, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant, Coyote Station and Hoot Lake Plant. The Utility plans to file a timely response to the request. At this time the Utility cannot determine what, if any, actions will be taken by the EPA.

The EPA issued changes to the existing New Source Review rules with respect to routine maintenance and repair and replacement activities in its Equipment Replacement Provision Rule on October 27, 2003. However, the U.S. Court of Appeals for the D.C. Circuit issued an order which stayed the effective date of the Equipment Replacement Provision rule pending judicial review. In a March 2006 decision the U.S. Court of Appeals for the D.C. Circuit struck down the EPA s Equipment Replacement

Provision. The EPA petitioned the original three-judge panel to reconsider its ruling and, at the same time, petitioned all of the court s judges to rehear the panel s decision. In June 2006, the judges denied both requests. The Department of Justice, on behalf of the EPA, and the Utility Air Regulatory Group filed a petition with the U.S. Supreme Court in November 2006 asking the Court to overturn the D.C. Circuit Court s decision to vacate the Equipment Replacement Provision. The petition was denied. On April 25, 2007, the EPA issued its supplemental proposal on the New Source Review Emissions Increase Rule and a final rule was expected. However, on December 10, 2008 the EPA announced that it decided not to finalize the proposed rule.

On November 20, 2006, the Sierra Club notified the Utility and the two other Big Stone Plant co-owners of its intent to sue alleging violations of the PSD requirements of the Act at the Big Stone Plant with respect to three past plant activities. The Sierra Club stated that unless the matter is otherwise fully resolved, it intends to file suit in the applicable district courts any time 60 days after November 20, 2006. 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 alleges certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleges 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 Clean Air Act and the South Dakota SIP. The Sierra Club alleges 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 seeks both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act 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 has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. The Utility and the co-owners have filed a motion to dismiss that is presently pending before the Court. The ultimate outcome of these matters cannot be determined at this time.

On September 22, 2008, the Sierra Club notified the Utility and the two other Big Stone Plant co-owners of its intent to sue alleging violations of the PSD and NSPS requirements of the Clean Air Act 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. The Utility believes that the Big Stone Plant is in material compliance with all applicable requirements of the Act.

The Coyote Station is subject to certain emission limitations under the PSD program of the Act. The EPA and the North Dakota Department of Health reached an agreement to identify a process for resolving several issues relating to the modeling protocol for the state s PSD program. Modeling was completed and the results were submitted to the EPA for its review. On April 19, 2005 the North Dakota Department of Health held a Periodic Review Hearing relating to the PSD Air Quality Modeling Report that was submitted to the EPA. One of the Hearing Officer s Findings and Conclusion was that the air quality relating to impacts of SO2 emissions is being adequately protected and that at 2002-2003 SO2 emission levels the relevant Class I increments are not violated.

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 increased 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. The Utility is an owner or part-owner of three baseload, coal-fired electricity generating plants and four fuel-oil or natural gas-fired combustion turbine peaking plants with a combined generating capability of 679 MW. In 2008, these plants emitted approximately 4.4 million tons of CO_2.

The Utility 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. Although several bills have been introduced in Congress that would compel reductions in CO_2 emissions, there are presently no federal mandatory GHG reduction requirements. 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 Clean Air Act. The Supreme Court sent the case back to the EPA, which must 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 Clean Air Act related to emissions from motor vehicles, a parallel provision of the Clean Air Act applies to stationary sources such as electric generators. Additionally, the EPA has announced that it plans to reconsider its decision to deny California s request for a waiver under the Act. If granted, the waiver would allow California to put into place motor vehicle standards to address GHG emissions. Finally, on July 11, 2008, the EPA issued an advance notice of proposed rulemaking on regulating GHG emissions under the Clean Air Act. Unless the Congress enacts legislation directing otherwise, the EPA could begin to regulate GHG emissions under the Act. The specific requirements of regulation under the Act s various programs, and thus their impact on the Utility, are uncertain at this time.

Although standards have not been developed at the national level, several states and regional organizations are 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. 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, and the MPUC currently has a docket outstanding in which they have solicited comments in regard to establishing the 2009 annual update of estimates of the likely range of costs of future CO_2 regulation on electricity regulation.

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, the Utility 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 2005, the Utility decreased its CO_2 intensity (lbs. of CO_2 /mWh generated) nearly 11%. The Utility plans to more than double that reduction by 2025. Big Stone II, the Utility proposed new generating plant is designed to incorporate supercritical pulverized coal technology that will increase plant efficiency by 20% and produce fly-ash that can replace cement in making concrete. In addition, transmission capacity above that which was needed for the plant was included in order to encourage regional wind energy development.

Conservation: Since 1992 the Utility has helped its customers conserve more than 1 million mWh of electricity. That is roughly equivalent to the amount of electricity that 90,000 average homes would have used in a year. The Utility continues to educate customers about energy efficiency and demand-side management and to work with regulators to develop new programs and measurements. The Utility s integrated resource plan calls for an additional 98 MW of conservation impacts by 2020.

Renewable energy: Since 2002 the Utility s customers have been able to purchase 100% of their electricity from wind generation through the Utility s TailWinds program. The MPUC has approved 160 MW of new wind generation in the most recent resource plan filing. Of that, 19.5 MW of purchased power agreements came on-line in December 2007 and 88.5 MW of owned wind resources were on-line by December 2008. Other projects are in the development phase and are expected to come on-line in the 2009 2010 time periods. The Utility has purchased all the electricity generated by fourteen 1.5 MW wind turbines located in southeastern North Dakota since 2004. The Utility supports Minnesota s new law requiring 25% of the electricity sold to Minnesota customers be obtained from renewable resources by 2025, especially with its customer protection provisions. This new law was based on the MPUC s Wind Integration Study, which assumed in its baseline the construction of the Big Stone II power plant and associated transmission. The Utility supports renewable energy objectives in North Dakota and South Dakota that 10% of all retail electricity sold within the states by the year 2015 is obtained from qualifying renewable energy sources.

Other: The Utility will continue to participate as a member of the EPA s SF_6 (sulfur hexafluoride) Emission Reduction Partnership for Electric Power Systems program. The partnership proactively is targeting a reduction in emissions of SF_6, a potent GHG. SF_6 has a global-warming potential 23,900 times that of CO_2. The Utility is involved in a pilot project to use methane from a municipal waste water treatment plant to generate electricity and is also studying the potential for other methane-related projects. Methane has a global-warming potential 20 times that of CO_2. The Utility participates in carbon sequestration research through the Plains CO_2 Reduction Partnership (PCOR) through the University of North Dakota s Energy and Environment Research Center. The PCOR Partnership is a collaborative effort of more than 50 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.

While the future financial impact of any proposed or pending climate change legislation 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 the Utility 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. The Utility has completed an information collection program for the Hoot Lake Plant cooling water intake structure, but given the Court decision the Utility is uncertain of the impact on the facility at this time.

The Utility 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. The Utility 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.

At the request of the MPCA, the Utility 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. The Utility provided a revised focus feasibility study for remediation alternatives to the MPCA in October 2004. The Utility and the MPCA have reached an agreement identifying the remediation technology and the Utility completed the projects in 2006. The effectiveness of the remediation is under 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, the Utility has incurred no significant costs as a result of these laws. The future total impact on the Utility 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. The Utility has not incurred any significant costs to date related to these laws. The Utility is not presently named as a potentially responsible party under the federal or state Superfund laws.

Capital Expenditures

The Utility is continually expanding, replacing and improving its electric facilities. During 2008, approximately $199 million was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2008 gross electric property additions, including construction work in progress, were approximately $400.7 million and gross retirements were approximately $58.8 million.

The Utility estimates that during the five-year period 2009-2013 it will invest approximately $698 million for electric construction, which includes $395 million for its share of expected expenditures for construction of the planned Big Stone II electric generating plant and related transmission assets if all necessary permits and approvals are granted on a timely basis and $66 million for anticipated expansion of transmission capacity in Minnesota. Other significant portions of the 2009-2013 capital budgets include wind generation projects and upgrades to the Utility s transmission system. If Big Stone II is not built, budgeted amounts for that project will be applied to alternative baseload generation projects that will be needed to meet the Utility s future generation requirements. In addition the Utility continues to review another wind project called the Luverne Wind Farm. The expected cost of this 49.5 MW project is $100 to $110 million and is not included in five-year estimate above. This project is subject to the Utility s ability to obtain acceptable financing terms and approval by the Company s Board of Directors.

Franchises

At December 31, 2008 the Utility 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 the Utility serves. The Utility believes that its franchises will be renewed prior to expiration.

Employees

At December 31, 2008 the Utility had approximately 697 equivalent full-time employees. A total of 421 employees are represented by local unions of the International Brotherhood of Electrical Workers. One labor contract was renewed in the fall of 2005 and has an expiration date in the fall of 2009. The other labor contract was renewed in the fall of 2008 and will expire in the fall of 2011. The Utility has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

PLASTICS

General

Plastics consist of businesses producing PVC pipe in the Upper Midwest and Southwest regions of the United States. The Company derived 9%, 12% and 15% of its consolidated operating revenues from the Plastics segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively. The Company derived 5%, 15% and 28% of its consolidated income from continuing operations from the Plastics segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively.

The 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 and Hampton, Iowa.

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 220 million pounds of PVC pipe annually. The companies will have the capacity to produce approximately 300 million pounds annually once planned expansions are completed and brought on-line.

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 highly fragmented and competitive, due to the large 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 94% and 95% of total resin purchases in 2008 and 2007, 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 2008, capital expenditures of approximately $9 million were made in the Plastics segment. Total capital expenditures for the five-year period 2009-2013 are estimated to be approximately $18 million. Estimated capital expenditures include approximately $2 million for remaining plant expansion costs at Vinyltech. New plant expansion capacity is not expected to be brought on-line until the economy improves and demand for PVC pipe increases. Vinyltech s plant expansion will include a new resin-blending system and two additional extrusion lines which will increase production capacity by 40% once they have been completed and brought on-line.

Employees

At December 31, 2008 the Plastics segment had approximately 130 full-time employees.

MANUFACTURING

General

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

The Company derived 36%, 31% and 28% of its consolidated operating revenues from the Manufacturing segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively. The Company has one customer within the Manufacturing segment that accounted for approximately 10.6% of the Company s consolidated revenues in 2008. The Company derived 15%, 29% and 26% of its consolidated income from continuing operations from the Manufacturing segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively. The following is a brief description of each of these businesses:

BTD Manufacturing, Inc., 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 recreation vehicle, gas fireplace, health and fitness and enclosure industries. BTD s wholly owned subsidiary, Miller Welding, 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.

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

ShoreMaster, Inc., 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 and Pine River, 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 2009 revenues of approximately $241 million compared with $295 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 or objectives exist in approximately one-half of the states. A federal production tax credit is in place through December 31, 2013.

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 2008, capital expenditures of approximately $48 million were made in the Manufacturing segment driven mainly by the DMI expansion projects in West Fargo, North Dakota and Tulsa, Oklahoma. Total capital expenditures for the Manufacturing segment during the five-year period 2009-2013 are estimated to be approximately $115 million. This investment is primarily to replace existing equipment at the manufacturing companies.

Employees

At December 31, 2008 the Manufacturing segment had approximately 1,850 full-time employees.

HEALTH SERVICES

General

Health Services consists of the DMS Health Group, 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 services, and rental of diagnostic medical imaging equipment.

The Company derived 9%, 11% and 12% of its consolidated operating revenues from the Health Services segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively. The decline in revenues between 2007 and 2008 reflects a change from the traditional dealership distribution of sales to an increase in manufacturer-direct sales commissions. The Company derived less than 1%, 3% and 4% of its consolidated income from continuing operations from the Health Services segment for each of the three years ended December 31, 2008, 2007 and 2006, respectively. The companies comprising the DMS Health Group 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 (MR), positron emission tomography (PET), PET/CT and cardiac catheterization labs. The business agreement with Philips has been renewed for a five year term ending 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 is also a supplier of medical film and related accessories. DMSHT markets mainly to hospitals, clinics and mobile imaging service companies.

DMS Imaging, Inc. (DMSI), a subsidiary of DMSHT located in Fargo, North Dakota, operates diagnostic medical imaging equipment, including CT, MRI, PET and PET/CT and provides nuclear medicine and other similar radiology services to hospitals, clinics, long-term care facilities and other medical providers. Regional offices are located in Minneapolis, Minnesota; Los Angeles, California; and Sioux Falls, South Dakota. DMS Imaging, Inc. provides services through four different business units:

DMS Imaging provides shared diagnostic medical imaging services (primarily mobile) for MR, CT, nuclear medicine, PET, PET/CT, ultrasound, mammography and bone density analysis.

DMS Interim Solutions offers interim and rental options for diagnostic imaging services.

DMS MedSource Partners develops long-term relationships with healthcare providers to offer dedicated in-house diagnostic imaging services.

DMS Portable X-Ray delivers portable x-ray, ultrasound and electrocardiography services to nursing homes and other facilities.

Combined, the DMS Health Group 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) scheduling, billing 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 Medicare and other 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. The Center for Medicare and Medicaid Services (CMS) is currently considering additional modifications to the Stark Law that may further limit the ability of physicians to provide certain imaging services in their practices.

The federal False Claims Act imposes liability on those who knowingly present or cause to be presented a false or fraudulent claim for payment to the federal government. Knowingly has been defined to include actions in deliberate ignorance and reckless disregard of the truth or falsity of such information. 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.

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.

DMSI maintains a limited number of Independent Diagnostic Testing Facilities (IDTFs) that enroll in the Medicare program as participating Medicare suppliers, so that they may receive reimbursement directly from the Medicare program for services provided to Medicare beneficiaries. CMS rule changes, effective January 1, 2008 increased oversight of IDTFs. 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 manner in which IDTFs are defined and enrolled in Medicare. These standards also include a provision prohibiting certain staff or space sharing arrangements. CMS implemented additional rule changes effective January 1, 2009 which may require some IDTFs to alter billing arrangements with healthcare clients.

The final rules published as part of the 2008 Medicare Physician Fee Schedule also alter the scope of the federal anti-markup rule for diagnostic tests, a federal law which delineates instances when 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.

CMS has also finalized new regulations that require suppliers of mobile diagnostic services 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 equipment and technicians 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 recent regulations that 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 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. Laws such as the Anti-Kickback Statute and HIPAA carry 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.

<u>Reimbursement</u>

The companies in the Health Services segment derive significant revenue from direct billings to customers and third-party payors such as Medicare, Medicaid, managed care and private health insurance companies for their diagnostic imaging services. The Health Services customers are primarily healthcare providers who receive the majority of their payments from third-party payors. Payments by third-party payors to such healthcare providers depend, in part, upon their patients health insurance policies.

New Medicare regulations reduced 2006 Medicare reimbursement for certain imaging services performed on contiguous body parts during the same day. In addition, the Deficit Reduction Act of 2005 (the DRA) limits 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 impacts a small number of imaging services provided by the Health Services segment. 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.

<u>Competition</u>

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 MR and PET/CT services, have access to greater financial resources than the Health Services companies. In addition, some of 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 the services from the Health Services company. 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 2008, capital expenditures of approximately $4 million were made in the Health Services segment. Total capital expenditures during the five-year period 2009-2013 are estimated to be approximately $27 million. 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 2009-2013 are estimated to be $76 million.

Employees

At December 31, 2008 the Health Services segment had approximately 357 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, foodservice and bakery 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 5%, 6% and 4% of its consolidated operating revenues from the Food Ingredient Processing segment for each of the years ended December 31, 2008, 2007 and 2006, respectively. This segment s contribution to consolidated income from continuing operations for each of three years ended December 31, 2008, 2007 and 2006 was 5%, 8% and (8%), respectively.

Customers

IPH sells to customers in the United States and internationally. Products are sold through company sales persons and broker sales representatives. Customers include end users in the food ingredient industries and distributors to the food ingredient industries and foodservice industries, 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 color. 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.

Backlog

IPH has backlog in place for 2009 of approximately 48 million pounds compared with 52 million pounds one year ago.

Regulations

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, safety and environmental control. 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 systems. During 2008, capital expenditures of $2 million were made in the Food Ingredient Processing segment. Total capital expenditures for the Food Ingredient Processing segment during the five-year period 2009-2013 are estimated to be approximately $14 million.

Employees

At December 31, 2008 the Food Ingredient Processing segment had approximately 375 full-time employees.

OTHER BUSINESS OPERATIONS

General

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries; fiber optic and electric distribution systems; wastewater and HVAC systems construction; transportation and energy services.

The Company derived 15%, 15% and 13% of its consolidated operating revenues from the Other Business Operations segment for each of the years ended December 31, 2008, 2007 and 2006, respectively. This segment s contribution to consolidated income from continuing operations for each of the three years ended December 31, 2008, 2007 and 2006 was 15%, 8% and 10%, 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.

Midwest Construction Services, Inc. (MCS), 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.

Otter Tail Energy Services Company, headquartered in Fergus Falls, Minnesota, provides technical and engineering services and energy efficient lighting primarily in North Dakota and Minnesota.

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 48 states and four Canadian provinces. During 2008 Wylie developed heavy-haul and wind tower transport operations. Wylie has trucking terminals in West Fargo, North Dakota; Fort Worth, Texas; Denver, Colorado; and Albertville, Minnesota.

Competition

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

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 recently entered the transportation market with specialized heavy-haul trucks and trailers capable of hauling wind tower sections. 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.

Backlog

The construction companies in the Other Business Operations segment have backlog in place of $71 million for 2009 compared with $77 million one year ago.

Capital Expenditures

Capital expenditures in this segment typically include investments in additional trucks, trailers and construction equipment. During 2008, capital expenditures of approximately $4 million were made in Other Business Operations. Capital expenditures during the five-year period 2009-2013 are estimated to be approximately $11 million for Other Business Operations. Operating leases are also used to finance the acquisition of trucks used by Wylie. Current operating lease commitments during the five-year period 2009-2013 are estimated to be $13 million.

Employees

At December 31, 2008 there were approximately 696 full-time employees in Other Business Operations. Moorhead Electric, Inc., a subsidiary of MCS, has 60 employees represented by local unions of the International Brotherhood of Electrical Workers and covered by a labor contract that expires on May 1, 2010. Foley Company has 230 employees represented by various unions, including Carpenters and Millwrights, Sheet Metal Workers, Laborers, Operators, Operating Engineers, Pipe Fitters, Steamfitters, Plumbers and Teamsters. Foley Company has several labor contracts with various expiration dates in 2009 and 2010. 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.

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, in the Company s press releases and in oral statements, words such as may, will, expect, anticipate, continue, estimate, project, believes or similar expressions 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.

The following factors, among others, could cause actual results for the Company to differ materially from those discussed in the forward-looking statements:

The Company is subject to federal and state legislation, regulations and actions that may have a negative impact on the Company s business and results of operations.

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

Future operating results of the electric segment will be impacted by the outcome of a rate case filed in North Dakota on November 3, 2008 requesting an overall increase in North Dakota rates of 5.14%. The filing included a request for an interim rate increase of 4.07%, which went into effect on January 1, 2009. Interim rates will remain in effect for all North Dakota customers until the NDPSC makes a final determination on the Utility s request, which is expected by August 1, 2009. If final rates are lower than interim rates, the Utility will refund North Dakota customers the difference with interest.

Any significant impairment of the Company s goodwill would cause a decrease in the Company s assets and a reduction in its net operating performance.

A sustained decline in the Company s common stock price below book value may result in goodwill impairments that could adversely affect the Company s results of operations and financial position, as well as credit facility covenants.

The terms of some of the Company s contracts could expose it to unforeseen costs and costs not within its control, which may not be recoverable and could adversely affect its results of operations and financial condition.

The Company is subject to risks associated with energy markets.

Certain of the Company s operating companies sell products to consumers that could be subject to recall.

Future operating results of the Company s electric segment will be impacted by the outcome of rate rider filings in Minnesota for transmission investments.

Certain costs currently included in the FCA in retail rates may be excluded from recovery through the FCA but may be subject to recovery through rates established in a general rate case.

Weather conditions or changes in the weather patterns can adversely affect the Company s operations and revenues.

Electric wholesale margins could be further reduced as the MISO market becomes more efficient.

Electric wholesale trading margins could be reduced or eliminated by losses due to trading activities.

The Company 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.

Wholesale sales of electricity from excess generation could be affected by reductions in coal shipments to the Big Stone and Hoot Lake plants due to supply constraints or rail transportation problems beyond the Company s control.

The Company s electric segment has capitalized $11.6 million in costs related to the planned construction of a second electric generating unit at its Big Stone Plant site as of December 31, 2008. If the project is abandoned for permitting or other reasons, a portion of these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

Federal and state environmental regulation could cause the Company to incur substantial capital expenditures and increased operating costs.

Existing or new laws or regulations addressing climate change or reductions of GHG emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in CO_2 emission levels or taxes on CO_2 emissions, that result in increases in electric service costs could negatively impact the Company s net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the Utility provides service or through increased market prices for electricity.

The Company may not be able to respond effectively to deregulation initiatives in the electric industry, which could result in reduced revenues and earnings.

If the Company is unable to achieve the organic growth it expects, its financial performance may be adversely affected.

The Company s plans to grow and diversify through acquisitions and capital projects may not be successful and could result in poor financial performance.

The Company s plans to acquire, grow and operate the Company s nonelectric businesses could be limited by state law.

Competition is a factor in all of the Company s businesses.

Economic uncertainty could have an adverse impact on the Company s future revenues and expenses.

Volatile financial markets and changes in the Company s debt rating could restrict the Company s ability to access capital and could increase borrowing costs and pension plan expenses. Disruptions, uncertainty or volatility in the financial markets can also adversely impact the results of operations, the ability of customers to finance purchases of goods and services, and the financial condition of the Company as well as exert downward pressure on stock prices and/or limit the Company s ability to sustain its current common stock dividend level.

As of December 31, 2008, the Company s defined benefit pension plan assets had declined significantly since December 31, 2007. The Company is not required to make a mandatory contribution to the pension plan in 2009. However, if the market value of pension plan assets continues to decline and relief under the Pension Protection Act is no longer granted, the Company could be required to contribute capital to the pension plan in 2009.

The price and availability of raw materials could affect the revenue and earnings of the Company s manufacturing segment.

The Company s food ingredient processing segment operates in a highly competitive market and is dependent on adequate sources of raw materials for processing. Should the supply of these raw materials be affected by poor growing conditions, this could negatively impact the results of operations for this segment.

The Company s food ingredient processing and wind tower manufacturing businesses could be adversely affected by changes in foreign currency exchange rates.

The Company s plastics segment is highly dependent on a limited number of vendors for PVC resin, many of which are located in the Gulf Coast regions, and a limited supply of resin. The loss of a key vendor or an interruption or delay in the supply of PVC resin could result in reduced sales or increased costs for this business. Reductions in PVC resin prices could negatively impact PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

Changes in the rates or method of third-party reimbursements for diagnostic imaging services could result in reduced demand for those services or create downward pricing pressure, which would decrease revenues and earnings for the Company s health services segment.

The Company s health services businesses may be unable to continue to maintain the agreements with Philips Medical from which it derives significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.

Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require the Company s health services operations to incur significant costs to upgrade their equipment.

Actions by regulators of the Company s health services operations could result in monetary penalties or restrictions in the Company s health services operations.

A significant failure or an inability to properly bid or perform on projects by the Company s construction businesses could lead to adverse financial results.

A further discussion of risk factors and cautionary statements is set forth under Risk Factors and Cautionary Statements and Critical Accounting Policies Involving Significant Estimates in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 29 through 36 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto. These factors are in addition to any other cautionary statements, written or oral, which may be made or referred to in connection with any forward-looking statement or contained in any subsequent filings by the Company with the Securities and Exchange Commission. The Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise.

Item 1A. RISK FACTORS

The information required by this Item is incorporated by reference to Management s Discussion and Analysis of Financial Condition and Results of Operations Risk Factors and Cautionary Statements on Pages 29 through 34 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

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 the Utility, Northern Municipal Power Agency, Montana-Dakota Utilities Co. and Northwestern Public Service Company. The Utility is the operating agent of the Coyote Station and owns 35% of the plant.

The Utility, 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. The Utility 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 127,000 kW. The oldest Hoot Lake Plant generating unit was constructed in 1948 (7,500 kW nameplate rating) and 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.

The Utility owns 27 wind turbines at the Langdon, North Dakota Wind Energy Center with a nameplate rating of 40,500 kW and 32 wind turbines at the Ashtabula Wind Energy Center located in Barnes County, North Dakota with a nameplate rating of 48,000 kW.

As of December 31, 2008 the Utility s transmission facilities, which are interconnected with lines of other public utilities, consisted of 48 miles of 345 kV lines; 405 miles of 230 kV lines; 799 miles of 115 kV lines; and 4,039 miles of lower voltage lines, principally 41.6 kV. The Utility 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 facilities and equipment used to manufacture PVC pipe, produce dehydrated potato products and perform metal stamping, fabricating and contract machining; construction equipment and tools; wind towers and other heavy metal fabricated products; thermoformed products; commercial and waterfront equipment; medical imaging equipment and a fleet of flatbed trucks and trailers.

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. The complaint alleges certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleges 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 Clean Air Act and the South Dakota SIP. The Sierra Club alleges 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 seeks both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act 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 has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. The ultimate outcome of these matters cannot be determined at this time.

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 the Utility and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES/PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by the Utility and NextEra Energy Resources, Inc. (fka FPL Energy, Inc.) (NextEra). RES/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 the Utility, 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 the Utility. The Utility 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 the Utility s Answer and, restated the allegations included in the initial Complaint. RES and PEAK Wind also added a request that the FERC rescind both the Utility s waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, the Utility filed a Reply, denying the allegations made by RES and PEAK Wind in its Answer. By Order issued on December 19, 2008, the Commission set the Complaint for hearing and established settlement procedures. The parties are engaged in settlement discussions. The Company believes the claims that the Utility has violated the FPA are without merit. The ultimate outcome of this matter cannot be determined at this time.

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 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the three months ended December 31, 2008.

Item 4A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF FEBRUARY 27, 2009)

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. Except as noted below, 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, Varistar.

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
John D. Erickson (50)	4/8/02	Present:	President and Chief Executive Officer
George A. Koeck (56)	4/10/00	Present:	Corporate Secretary and General Counsel
Lauris N. Molbert (51)	6/10/02	Present:	Executive Vice President and Chief Operating Officer
Kevin G. Moug (49)	4/9/01	Present:	Chief Financial Officer
Charles S. MacFarlane (44)	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.

PART II

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

The information required by this Item is incorporated by reference to the first sentence under Otter Tail Corporation Stock Listing on Page 72, to Selected Consolidated Financial Data on Page 18, to Retained Earnings Restriction on Page 61 and to Quarterly Information on Page 69 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto. The Company did not repurchase any equity securities during the three months ended December 31, 2008.

PERFORMANCE GRAPH

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

The graph below compares the cumulative total shareholder return on the Company s common shares for the last five fiscal years with the cumulative return of The NASDAQ Stock Market Index and the Edison Electric Institute Index (EEI) over the same period (assuming the investment of $100 in each vehicle on December 31, 2003, and reinvestment of all dividends).

	2003	2004	2005	2006	2007	2008
OTC	$100.00	$ 99.61	$117.64	$131.54	$151.22	$105.97
EEI	$100.00	$122.84	$142.56	$172.14	$200.65	$148.68
NASDAQ	$100.00	$108.84	$111.16	$122.11	$132.42	$ 63.80

Item 6. SELECTED FINANCIAL DATA

The information required by this Item is incorporated by reference to Selected Consolidated Financial Data on Page 18 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

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

The information required by this Item is incorporated by reference to Management s Discussion and Analysis of Financial Condition and Results of Operations on Pages 19 through 37 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this Item is incorporated by reference to Quantitative and Qualitative Disclosures About Market Risk on Pages 32 through 34 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this Item is incorporated by reference to Quarterly Information on Page 69, the Company s audited financial statements on Pages 39 through 69 and Report of Independent Registered Public Accounting Firm on Page 38 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

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

None.

Item 9A. 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, 2008, 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, 2008.

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, 2008 that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

The annual report of the Company s management on internal control over financial reporting is incorporated by reference to Management s Report Regarding Internal Control Over Financial Reporting on Page 37 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

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 incorporated by reference to Report of Independent Registered Public Accounting Firm on Page 38 of the Company s 2008 Annual Report to Shareholders, filed as an Exhibit hereto.

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 2009 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 4A 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 2009 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 2009 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 2009 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 2009 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 2009 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 2009 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2008 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	909,632(1)	$ 14.51	1,017,326(2)
1999 Employee Stock Purchase Plan		N/A	330,565(3)
Equity compensation plans not approved by security holders			
Total	909,632	$ 14.51	1,347,891

(1) Includes 114,800, 109,000, and 88,050 performance based share awards made in 2008, 2007 and 2006, respectively, 73,585 restricted stock units outstanding as of December 31,

2008, and 16,495 phantom shares as part of the deferred director compensation program and excludes 73,447 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 and Election of Directors in the Company s definitive Proxy Statement for the 2009 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 2009 Annual Meeting.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) List of documents filed:

(1) and (2) See Table of Contents on Page 51 hereof.

(3) See Exhibit Index on Pages 52 through 59 hereof.

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

SIGNATURES

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

OTTER TAIL CORPORATION

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

Dated: February 27, 2009

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)	)	
	)	By /s/ John D. Erickson
	)	
John C. MacFarlane	)	John D. Erickson
Chairman of the Board and Director	)	Pro Se and Attorney-in-Fact
	)	Dated February 27, 2009
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	)	

OTTER TAIL CORPORATION

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FINANCIAL STATEMENTS, SUPPLEMENTARY FINANCIAL DATA, SUPPLEMENTAL FINANCIAL SCHEDULES INCLUDED IN ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2008

The following items are incorporated in this Annual Report on Form 10-K by reference to the registrant s Annual Report to Shareholders for the year ended December 31, 2008 filed as an Exhibit hereto:

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.

Exhibit Index
to
Annual Report
on Form 10-K
For Year Ended December 31, 2008

	Previously Filed		
	File No.	**As Exhibit No.**	
3-A	8-K filed 4/10/01	3	Restated Articles of Incorporation, as amended (including resolutions creating outstanding series of Cumulative Preferred Shares).
3-B	10-K for year ended 12/31/07	3-B	Restated Bylaws, as amended.
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-B	8-K filed 8/01/08	4.1	Credit Agreement, dated as of July 30, 2008, among the Company, dba 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-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-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-E	8-K filed 10/5/07	4.1	Credit Agreement, dated as of October 2, 2007, among Varistar Corporation, the Banks named therein, U.S.

Bank National Association, as agent for the Banks and as Lead Arranger, and Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents.

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	Previously Filed File No.	As Exhibit No.	
4-E-1	8-K filed 12/7/07	4.1	First Amendment to Credit Agreement, dated as of November 30, 2007, to Credit Agreement, dated as of October 2, 2007.
4-E-2	8-K filed 12/30/08	4.1	Amended and Restated Credit Agreement, dated as of December 23, 2008 among Varistar Corporation, the Banks named therein, U.S. Bank National Association, as agent for the Banks and as Lead Arranger, and Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents.
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.

	Previously Filed		
	File No.	As Exhibit No.	
10-E-3	10-K for year ended 12/31/89	10-E-3	Supplement Two dated June 10, 1983.
10-E-4	10-K for year ended 12/31/90	10-E-4	Supplement Three dated June 6, 1985.
10-E-5	10-K for year ended 12/31/92	10-E-5	Supplement No. Four, dated as of September 10, 1986.
10-E-6	10-K for year ended 12/31/92	10-E-6	Supplement No. Five, dated as of January 7, 1993.
10-E-7	10-K for year ended 12/31/93	10-E-7	Supplement No. Six, dated as of December 2, 1993
10-F	10-K for year ended 12/31/89	10-F	Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970).
10-F-1	10-K for year ended 12/31/89	10-F-1	Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-F-2	10-K for year ended 12/31/91	10-F-2	Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-F-3	10-K for year ended 12/31/91	10-F-3	Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-F-4	10-K for year ended 12/31/91	10-F-4	Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-F-5	10-Q for quarter ended 9/30/03	10.1	Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-F-6	10-K for year ended 12/31/92	10-F-5	Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-G		10.3	

10-Q for quarter ended 06/30/04	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).

	Previously Filed File No.	As Exhibit No.	
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.

	Previously Filed		
	File No.	As Exhibit No.	
10-J-1	10-Q for quarter ended 06/30/05	10.1	Big Stone II Power Plant Participation Agreement by and among the Company, Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners (dated as of June 30, 2005).
10-J-1a	10-Q for quarter ended 6/30/06	10.6	Amendment No. 1, dated as of June 1, 2006, to Participation Agreement (dated as of June 30, 2005).
10-J-1b	8-K filed 8/31/06	10.1	Amendment No. 2, dated as of August 18, 2006, to Participation Agreement (dated as of June 30, 2005).
10-J-1c	8-K filed 10/11/06	10.1	Amendment No. 3, effective September 1, 2006, to Participation Agreement (dated as of June 30, 2005).
10-J-1d	8-K filed 6/19/07	10.1	Amendment No. 4, dated as of June 8, 2007, to Participation Agreement (dated as of June 30, 2005).
10-J-1e	8-K filed 9/12/07	10.1	Amendment No. 5, dated as of September 1, 2007, to Participation Agreement (dated as of June 30, 2005).
10-J-1f	8-K filed 9/24/07	10.1	Amendment No. 6, dated as of September 20, 2007, to Participation Agreement (dated as of June 30, 2005).
10-J-2	10-Q for quarter ended 06/30/05	10.2	Big Stone II Power Plant Operation & Maintenance Services Agreement by and among the Company, Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency, as Owners, and the Company, as Operator (dated as of June 30, 2005).
10-J-3	10-Q for quarter ended 06/30/05	10.3	Big Stone I and Big Stone II 2005 Joint Facilities Agreement by and among the Company, Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation dba NorthWestern Energy, Southern Minnesota Municipal

			Power Agency and Western Minnesota Municipal Power Agency, as Owners (dated as of June 30, 2005).
10-J-3a	8-K filed 8/25/06	10.1	Amendment No. 1, dated as of July 13, 2006, to Joint Facilities Agreement (dated as of June 30, 2005).

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	Previously Filed File No.	As Exhibit No.	
10-K-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-L	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-L-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-M	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-N-1	10-K for year ended 12/31/02	10-N-1	Deferred Compensation Plan for Directors, as amended*
10-N-2	8-K filed 02/04/05	10.1	Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-2a	10-K for year ended 12/31/06	10-N-2a	First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-N-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).*

	Previously Filed		
	File No.	As Exhibit No.	
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-1	10-Q for quarter ended 6/30/02	10-A	Executive Employment Agreement, John Erickson.*
10-O-2	10-Q for quarter ended 6/30/02	10-B	Executive Employment Agreement and amendment no. 1, Lauris Molbert.*
10-O-3	10-Q for quarter ended 6/30/02	10-C	Executive Employment Agreement, Kevin Moug.*
10-O-4	10-Q for quarter ended 6/30/02	10-D	Executive Employment Agreement, George Koeck.*
10-P-1	8-K filed 11/2/07	10.1	Change in Control Severance Agreement, John Erickson.*
10-P-2	8-K filed 11/2/07	10.2	Change in Control Severance Agreement, Lauris Molbert.*
10-P-3	8-K filed 11/2/07	10.3	Change in Control Severance Agreement, Kevin Moug.*
10-P-4	8-K filed 11/2/07	10.4	Change in Control Severance Agreement, George Koeck.*
13-A			Portions of 2008 Annual Report to Shareholders incorporated by reference in this Form 10-K.
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.

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	Previously Filed		
	File No.	As Exhibit No.	
32.2			Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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