OTTER TAIL CORPORATION

STRONG FOUNDATION BRIGHT FUTURE

Entering Our Next Century

2008 ANNUAL REPORT

CONTENTS

HIGHLIGHTS

HIGHLIGHTS of the year

	2008	2007	Percent Change
CONSOLIDATED OPERATIONS:			
Total Operating Revenues	$ 1,311,197,000	$ 1,238,887,000	5.8
Net Income	35,125,000	53,961,000	(34.9)
Basic Earnings Per Share	1.09	1.79	(39.1)
Diluted Earnings Per Share	1.09	1.78	(38.8)
Dividends Per Common Share	1.19	1.17	1.7
Return on Average Common Equity	6.0%	10.5%	(42.9)
Book Value Per Common Share	19.10	17.51	9.1
Cash Flow from Continuing Operations	111,321,000	84,812,000	31.3
Number of Common Shares Outstanding	35,384,620	29,849,789	18.5
Number of Common Shareholders	14,627	14,509	0.8
Closing Stock Price	23.33	34.60	(32.6)
Total Return (share price appreciation plus dividends)	(29.1)%	14.8%	—
Total Market Value of Common Stock	825,523,000	1,032,803,000	(20.1)
Total Employees (all companies and corporate, includes temporary and part-time)	4,318	4,300	0.4
ELECTRIC OPERATIONS:			
Operating Revenues:			
Retail	$ 287,631,000	$ 276,894,000	3.9
Wholesale—Net of Purchased Power Costs	27,236,000	25,640,000	6.2
Other	24,859,000	20,624,000	20.5
Total Electric Operating Revenues	$ 339,726,000	$ 323,158,000	5.1
Total Retail Electric Sales (kwh)	4,241,907,000	4,123,831,000	2.9
Operating Income	55,757,000	45,755,000	21.8
Customers	129,268	129,342	—
Gross Plant Investment	1,231,193,000	1,062,689,000	15.9
Total Assets	992,159,000	813,565,000	22.0
Capital Expenditures	198,798,000	104,288,000	90.6
Employees (includes temporary and part-time)	730	714	2.2
NONELECTRIC OPERATIONS:			
Operating Revenues	$ 971,471,000	$ 915,729,000	6.1
Operating Income	17,235,000	55,019,000	(68.7)
Total Assets	700,428,000	641,189,000	9.2
Capital Expenditures	67,090,000	57,697,000	16.3
Employees (includes temporary and part-time)	3,528	3,533	(0.1)

WHO WE ARE

Otter Tail Corporation's strategy is to create long-term value for our shareholders, customers and employees by owning diverse, well-run companies. We target sound opportunities and provide the right resources for success. Our operating companies include an electric utility and businesses in manufacturing, infrastructure, health services and food ingredient processing.

Otter Tail companies collectively serve customers worldwide from our operations in the United States and in Canada. Corporate offices are in Fergus Falls, Minnesota, and Fargo, North Dakota. Our stock trades on the NASDAQ Global Select Market under the ticker symbol OTTR.

STRONG FOUNDATION | BRIGHT FUTURE

Entering Our Next Century

Our foundation extends over a century, with the incorporation of Otter Tail Power Company in 1907. The electric utility marks its official centennial from the point in 1909 when electrical service first brightened the lives of customers. This strong heritage includes successful diversification into other industries over the past two decades, as we charted new directions to increase shareholder value. Our strategy remains the right path to long-term growth and stability. And our investments in exciting growth opportunities—such as wind energy—will help create a bright future.

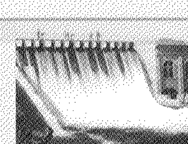
HISTORY

1871 George Wright, founder of Fergus Falls, Minnesota, builds Central Dam along the Otter Tail River.

1879 Thomas Edison invents the lightbulb.

1882 Vernon Wright inherits Central Dam from his father.

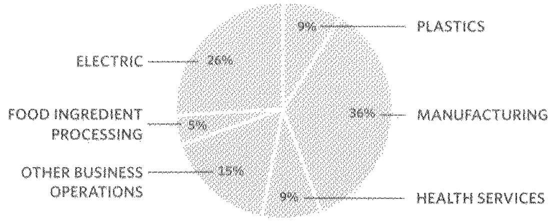
1907 Wright and other investors incorporate Otter Tail Power Company and start work on Dayton Hollow hydroelectric plant.



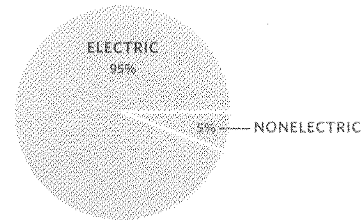
1909 Dayton Hollow hydroelectric plant begins serving customers in Wahpeton, North Dakota.

1926 Wide diffusion of ownership begins with the sale of special common stock.

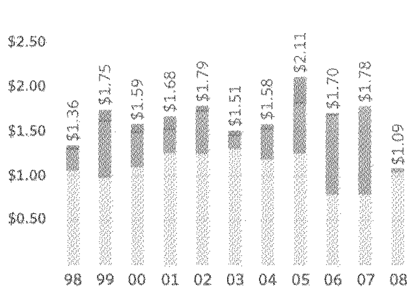
REVENUES



NET INCOME



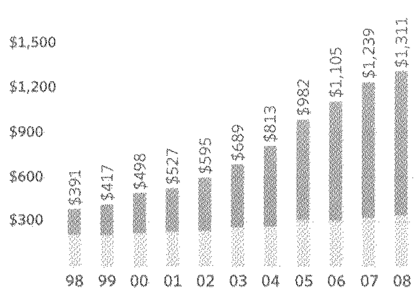
EARNINGS PER SHARE



Disappointing results in 2008 were a departure from general growth trend.

Electric
Nonelectric continuing operations
Nonelectric discontinued operations

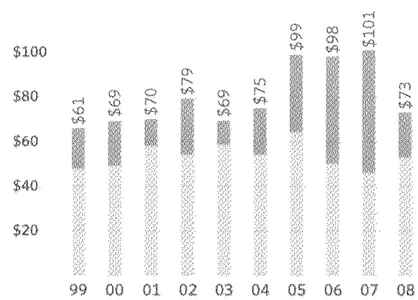
REVENUE GROWTH (MILLIONS)



Total company revenue has grown at a compounded annual rate of 12.9% over the past ten years.

Electric
Nonelectric continuing operations

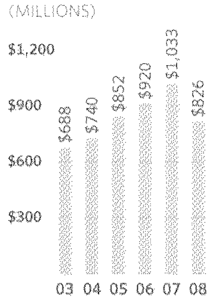
OPERATING INCOME (MILLIONS)



Operating income has grown at a compounded annual rate of 2.9% over the past ten years.

Electric
Nonelectric continuing operations

MARKET CAPITALIZATION (MILLIONS)



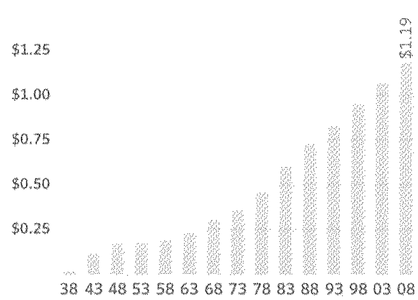
Our market capitalization has increased 20% over the past five years. Over that same period of time, we've paid out $167 million in common dividends.

DIVIDEND PAYOUT RATIO

Over the past five years dividends have increased while the average payout rate has been 73%. Earnings per share in 2005 includes $0.34 related to a net gain on the sale of discontinued operations.

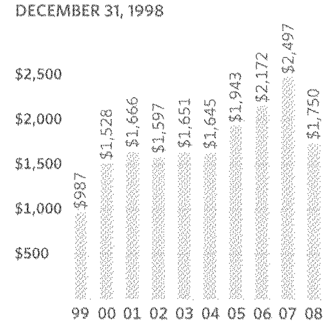
Earnings per share
Dividend per share

DIVIDEND PAYMENT HISTORY



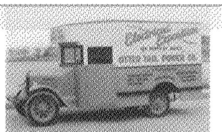
Otter Tail has paid common dividends every year since 1938.

GROWTH OF $1,000 INVESTMENT IN OTTER TAIL COMMON STOCK MADE DECEMBER 31, 1998



Shareholder value has grown at a compounded annual rate of 5.8% over the past ten years.

1936 Congress passes the Rural Electrification Act.



1937 Otter Tail Power Company begins serving area rural cooperatives.

1938 Dividends resume after a five-year freeze and continue to present day without interruption.

1941 Otter Tail Power Company grows by 25% following a merger with another utility.

1944 The company reaches its maximum territorial size, serving more than 400 communities in Minnesota, North Dakota and South Dakota.

1946 Electricity use skyrockets after World War II. While planning for additional steam generation, the company adds diesel and gas generators.

JOHN ERICKSON • PRESIDENT AND CEO

TO OUR SHAREHOLDERS

DEAR SHAREHOLDER,

We entered 2008 with a significant amount of momentum and a strong sense of optimism. Clearly, it would have been difficult to foresee the scale of the economic challenges that our company—along with companies in virtually every sector—would face during the year. The United States economy entered a formal recession. Capital markets froze and access to credit dwindled, sidelining growth plans for many companies and putting pressure on working capital resources. Many of our nonelectric businesses, which as a group produced back-to-back record years in 2006 and 2007, serve end markets that were significantly affected by the sweeping economic decline in 2008. Additionally, one of our businesses, DMI Industries faced operational challenges that can accompany rapid expansion. In contrast, we are encouraged that Otter Tail Corporation's core electric business, Otter Tail Power Company, posted solid results in 2008.

Like many companies, Otter Tail Corporation and our operating companies took a variety of actions, as the year progressed, to address these near-term financial challenges. We scrutinized expenses and explored new ways to increase efficiencies and improve execution. We reined in discretionary spending and reassessed capital projects. These efforts were, and will continue to be, instrumental in supporting Otter Tail Corporation's financial health.

But while these economic headwinds persist as we enter 2009, they have done little to diminish our belief in a bright long-term future for Otter Tail Corporation. To justify that optimism, we need to look no further than our strong 100-year foundation—a foundation based on delivering an essential service through our core electric business and extending to this day through our diversified platform of operating companies. Our foundation not only provides a stable base for long-term performance, but it also provides flexibility to pursue our growth and diversification strategies.

2008 ACCOMPLISHMENTS—PAVING THE WAY FOR A BRIGHT FUTURE

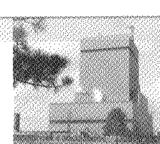
Despite current economic challenges, we believe Otter Tail Corporation's long-term growth potential is evident. We expect much of our growth over the next few years to come from major capital investments in our existing operating companies. Considering the

1953
Fergus Falls voters overwhelmingly support the sale of the city's municipal electrical system to Otter Tail Power Company, which agrees to build its new General Office there.

1963
Directors declare a two-for-one common stock split.

1971
Otter Tail Power Company stock is listed on NASDAQ under the ticker symbol OTTR.

1975
The 450-MW Big Stone Plant goes on line near Milbank, South Dakota, and six smaller plants are phased out. Dividends increase annually from this year onward.



1981
Coyote Station, with a capacity of 420 MW, goes on line near Beulah, North Dakota.

1988
Directors again declare a two-for-one common stock split.

TO CREATE VALUE FOR OUR CUSTOMERS, SHAREHOLDERS AND EMPLOYEES BY WORKING TOGETHER TO GROW OUR COMPANIES:

- For customers, by focusing on their needs and providing quality products and services.
- For shareholders, by providing returns on their investments that consistently are above average.
- For employees, by providing opportunities in a challenging, rewarding environment.

OUR MISSION

dramatic changes in the capital markets, we are pleased that we were able to take some concrete steps toward that future in 2008.

We completed a common stock offering, which generated nearly $150 million in net proceeds to fund growth opportunities. Few initiatives demonstrate our future growth potential better than our commitment to wind energy. We invested the majority of the offering's net proceeds to build and own 32 wind turbines capable of generating 48 megawatts of wind energy generation at the 200-megawatt Ashtabula Wind Center in Barnes County, North Dakota, which is one of the largest wind energy farms in the state. Our ownership in the Ashtabula project is an economical addition to Otter Tail Power Company's resource mix and marks a sizeable increase in Otter Tail Corporation's commitment to renewable energy.

We also devoted proceeds from that stock offering to expand DMI Industries' wind-tower manufacturing facilities in Tulsa, Oklahoma, and West Fargo, North Dakota. Although some of the operational challenges that can accompany rapid growth—such as achieving timely production efficiencies—have affected this expansion, we have made progress in managing through these issues. DMI has been our fastest-growing business and, with this expansion, DMI will increase production capacity significantly at both facilities to maintain our market share as a leader in the wind-tower manufacturing industry. Once completed, DMI will be one of the largest wind-tower manufacturers in North America and well positioned for significant growth in the renewable energy sector.

Otter Tail Power Company also entered into an agreement with M-Power, LLC, to purchase a 49.5-megawatt portion of the Luverne Wind Farm under development in east central North Dakota. The Luverne Wind Farm would increase the amount of economical wind-generated electricity owned or purchased by Otter Tail Power Company to nearly 180 megawatts, which is enough to power approximately 52,000 homes.

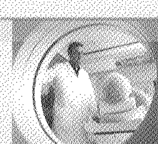
BTD Manufacturing, which provides metal fabrication services, acquired Miller Welding & Iron Works of Washington, Illinois. Both BTD and Miller are strong companies, and we believe the combination of these two entities will open opportunities for BTD to expand in existing and new markets. Additionally, we expect this acquisition to provide growth and synergies with BTD and other Otter Tail companies, such as DMI Industries, as we seek to capitalize on the rising demand for wind energy.

As we enter 2009, we see multiple opportunities to further invest in our core electric business and also in our nonelectric businesses. Naturally, these investments require access to additional capital. Although no one can predict when or how quickly the credit environment will improve, we are hopeful for such an improvement in 2009 and the opportunity to more aggressively pursue our plans for organic growth and expansion.

1989 — To address earnings growth needs, Otter Tail Power Company forms Mid-States Development to acquire and oversee nonelectric businesses.

1990 — Mid-States Development acquires DMI Industries, a heavy steel manufacturer.

1992 — Moorhead Electric is acquired and later is renamed Midwest Construction Services to reflect its electric and transmission construction work.



1993 — DMS Health Group is acquired and later is renamed DMS Health Technologies. DMS sells, services and operates diagnostic imaging equipment.

1995 — Acquisitions include PVC manufacturer Northern Pipe Products and metal fabricator BTD Manufacturing.

1998 — Mid-States Development changes its name to Varistar Corporation.

2008 FINANCIAL RESULTS

Certainly, our financial results for 2008 do not reflect the financial performance we had set out to achieve at the beginning of the year. Instead, our results reflect the challenges presented by prevailing economic conditions and operating hurdles we must overcome in executing certain of our growth strategies. These challenges, as well as the impact of efficiency initiatives and costs related to investments in future growth opportunities, influenced our financial results. Our financial outcomes for 2008 are as follows:

- Operating revenues reached a record level of more than $1.3 billion.
- Net income declined to $35.1 million.
- Earnings per share were $1.09.
- The common dividend paid in 2008 increased to $1.19 per share.
- Stock price declined 33% in 2008, resulting in a total return, net of dividend, of -29.1%. These returns were in line with the broad markets in general, as well as the major utility indexes.

Otter Tail Corporation remains financially strong today. We have a solid balance sheet, a strong capital structure, are compliant with all debt covenants and have sufficient liquidity under our existing credit facilities to provide for our working capital requirements.

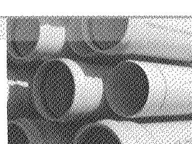
We were honored once again this year by *Public Utilities Fortnightly* as one of the nation's top-performing energy companies. The publication's rating was based on 2005 through 2007 averages of profitability, dividend yield, cash flow, return on equity, return on assets and sustainable growth. This is the fourth year in a row that Otter Tail Corporation has received this honor.

In addition, we were again recognized in 2008 as a Mergent Dividend Achiever for our reliable dividend. We have provided a dividend without interruption for more than 70 years, and our commitment to dividend income continues in 2009. The Board of Directors' decision on the first quarter dividend reflects the corporation's financial strength and confidence in the future, while exhibiting prudence in difficult economic times.

A STRONG FOUNDATION

Incorporated in 1907, Otter Tail Power Company delivered electricity to its first customer in 1909. We celebrate the centennial of this event in 2009. Recognizing the hard work and innovation of those who have served Otter Tail Corporation during the past

1999 — Varistar acquires E.W. Wylie Corporation, a national trucking firm.



2000 — PVC pipe manufacturer Vinyltech is acquired. Directors again declare a two-for-one common stock split.

2001 — The corporate name changes to Otter Tail Corporation to reflect diversification. The Varistar brand is retired, and the utility continues with the Otter Tail Power Company brand. Custom packaging manufacturer T.O. Plastics is acquired.

2002 — Otter Tail Corporation acquires ShoreMaster, a waterfront equipment manufacturer.

2003 — Mechanical and prime contractor Foley Company is acquired.

2004 — Dehydrated potato processor Idaho Pacific is acquired.

INTEGRITY We conduct business responsibly and honestly.
SAFETY We provide safe workplaces and require safe work practices.
PEOPLE We build respectful relationships and create an environment where talented people thrive.
PERFORMANCE We strive for excellence, act on opportunity and deliver on commitments.
COMMUNITY We improve the communities where we work and live.

OUR VALUES

century and those who serve this company today is an honor and privilege. As we recognize this achievement, we also are bound by a deep sense of duty to extend this heritage, strengthen this organization and continue our growth.

Today Otter Tail Corporation is a solid company. We have weathered tough times, from the Great Depression through the energy crisis of the 1970s. The stability of our company demonstrates our resilience in the face of such challenges, our ongoing innovation and our commitment to fiscal and operating discipline. We carry those qualities into 2009.

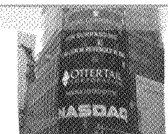
Our company has a bright future. In 1989 we took the bold step to expand our operations by diversifying into other industries—a move designed to build on the strength of our core electric business and improve our overall growth profile. This long-term strategy has proven successful and visionary. Today we not only see additional growth opportunities across our nonelectric businesses, but we also see the opportunity to grow the foundation of the core electric business through investments in transmission and generation—both baseload and renewable. We welcome this relatively new business dynamic. We remain committed to the philosophy that responsibly delivering electric power to consumers demands a balanced approach using a broad array of energy resources including renewables, coal, natural gas and energy efficiency. While we will continue to scrutinize our mix of operating companies and their return potential, we believe that Otter Tail Corporation has established a strong platform for growth.

We remain committed to our vision. When a company faces adversity, the vision and values that support it become more important than ever. We remain committed to our vision of being a recognized leader in growing great companies and developing talented people. That vision is anchored in our values: integrity, safety, people, performance and community. With so many communities struggling with difficult economic conditions, I am particularly proud of the efforts made by employees at all of our operating companies during 2008 toward community stewardship. I believe this commitment reflects an ethic ingrained within the people of Otter Tail Corporation.

A strong foundation, a bright future. On behalf of all our employees and our board of directors, I extend thanks to you, our shareholders, for your support in 2008. You are a critical part of our strong foundation. As we move into 2009, we look forward to meeting challenges, pursuing opportunities and sharing in our success together.

Sincerely,

John Erickson • President and CEO • February 2009



2005

Revenues surpass $1 billion for the first time in the corporation's history.

2006

Otter Tail Corporation is named to the NASDAQ Global Select Market. North Dakota-based DMI begins filling orders for wind towers from a second plant in Ontario, Canada.

2007

With other utility partners, Otter Tail Power Company begins building North Dakota's largest wind farm to date. DMI constructs a third plant in Tulsa, Oklahoma.

2008

Otter Tail Power Company announces two more major wind projects based in North Dakota. In February 2008 Otter Tail Corporation reports record revenues and net income for the prior year.

2009

Otter Tail Power Company celebrates 100 years of exceptional service to customers.

OTTER TAIL CORPORATION

ELECTRIC	MANUFACTURING	INFRASTRUCTURE PRODUCTS AND SERVICES	FOOD INGREDIENT PROCESSING	HEALTH SERVICES

ELECTRIC

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

MANUFACTURING

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

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

ShoreMaster, Inc.
Waterfront equipment manufacturer
Fergus Falls, MN / 2002
Dennis Kostrzewski
320 employees
www.shoremaster.com

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

INFRASTRUCTURE PRODUCTS AND SERVICES

PLASTICS

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

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

OTHER BUSINESSES

Construction

Foley Company
Mechanical and prime contractor
Kansas City, MO / 2003
Chris Callegari
270 employees
www.foleycompany.com

Midwest Construction Services, Inc.
Electrical and transmission constructor
Moorhead, MN / 1992
Shane Waslaski
230 employees
www.mwcsi.com

Transportation

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

FOOD INGREDIENT PROCESSING

Idaho Pacific Holdings, Inc.
Dehydrated potato processor
Ririe, ID / 2004
Dick Nickel
390 employees
www.idahopacific.com

HEALTH SERVICES

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

CHART LEGEND

Company Name
Company description
Location of headquarters and year acquired
Operating company leader
Employees (approximate number including part-time and temporary)
Web site address

ELECTRIC

IN 2008 OTTER TAIL POWER COMPANY CONTINUED ITS COMMITMENT TO DEVELOPMENT OF LOW-COST RENEWABLE ENERGY AND A DIVERSIFIED ENERGY PORTFOLIO BY COMPLETING ITS 48-MEGAWATT OWNERSHIP PORTION OF THE ASHTABULA WIND CENTER IN EASTERN NORTH DAKOTA.

OTTER TAIL POWER COMPANY—ON FOR GENERATIONS

Otter Tail Power Company generated its first kilowatt-hour in early 1909 at Dayton Hollow hydroelectric station, which continues to operate. During the past century the company has provided reliable and affordable electric service, delivered in an environmentally sensitive manner, to customers in Minnesota, North Dakota and South Dakota. Today nearly 130,000 homes and businesses in 423 communities benefit and will help Otter Tail Power Company celebrate a centennial of service in 2009.

SAFETY—THE COMPANY'S UNDERPINNING

Otter Tail Power Company employees worked more than 1.7 million hours during 2008 without a lost workday—an impressive achievement considering the nature of the company's business and the environment in which it operates. In May 2008 the company received an Award of Honor from the Minnesota Safety Council, recognizing outstanding achievement.

In 2008 Big Stone Plant completed a project with local conservation groups—Pheasants Forever, Grant County Conservation District, National Wild Turkey Federation, and the South Dakota Department of Game, Fish, and Parks—to enhance wildlife habitat on plant property.

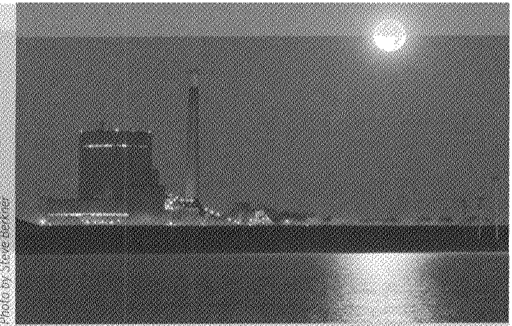


Photo by Steve Berkner

TRANSMISSION INFRASTRUCTURE INVESTMENTS CONTINUE

The company continues to plan for a major transmission construction project in north-central Minnesota. The Bemidji-Grand Rapids line is one of four transmission projects in the first phase of CapX 2020, a multi-utility endeavor that involves reliability improvements in several regions of the state. CapX 2020 will also help facilitate orderly integration of the region's burgeoning wind generation industry. Otter Tail Power Company is a participant in three of the four projects and lead developer of the Bemidji-Grand Rapids project. The Bemidji-Grand Rapids line is expected to be permitted in 2010.

LOW-COST WIND ENERGY DEVELOPMENT CONTINUES

In addition to vigorous demand-side management and energy-efficiency programs, the company continues to invest in wind energy. Otter Tail Power Company plans for 39% of its energy resource additions between 2005 and 2020 to come from wind energy resources and 14% from demand-side management programs. This will augment the company's planned investment in baseload fossil-fuel generation resources.

In January the Langdon Wind Energy Center in northeastern North Dakota was fully commissioned. The company owns 40.5 megawatts and purchases 19.5 megawatts at Langdon. Construction began in June on the Ashtabula Wind Center in eastern North Dakota, and Otter Tail Power Company's 48-megawatt ownership portion of this 200-megawatt project was generating electrical energy by November. In October 2008 the company and a North Dakota-based wind developer began permitting procedures to construct the 157-megawatt Luverne Wind Farm in east-central North Dakota. Otter Tail Power Company expects to own 49.5 megawatts of the Luverne facility.

BIG STONE II RECEIVES MAJOR PERMITS

Together with four other utilities, Otter Tail Power Company continued the study and development of a proposed 500- to 580-megawatt coal-fired power plant to address the region's baseload needs. If built, the proposed Big Stone II would be adjacent to the existing Big Stone Plant near Milbank, South Dakota. Significant progress was made in 2008 with major permits, including an advance determination of prudence by the North Dakota Public Service Commission, an air-quality permit by the South Dakota Board of Minerals and Environment and a certificate of need and route permit by the Minnesota Public Utilities Commission.

CUSTOMER SATISFACTION REACHES NEW HIGH

Otter Tail Power Company achieved its highest overall customer satisfaction score among customers who have initiated a transaction with the company since the data have been compiled. The achievement was driven by residential and commercial customers who said they were most satisfied with the timely manner in which the company responded to outages. The company credits its highly motivated and well trained employees for making the first-call-resolution concept a priority.

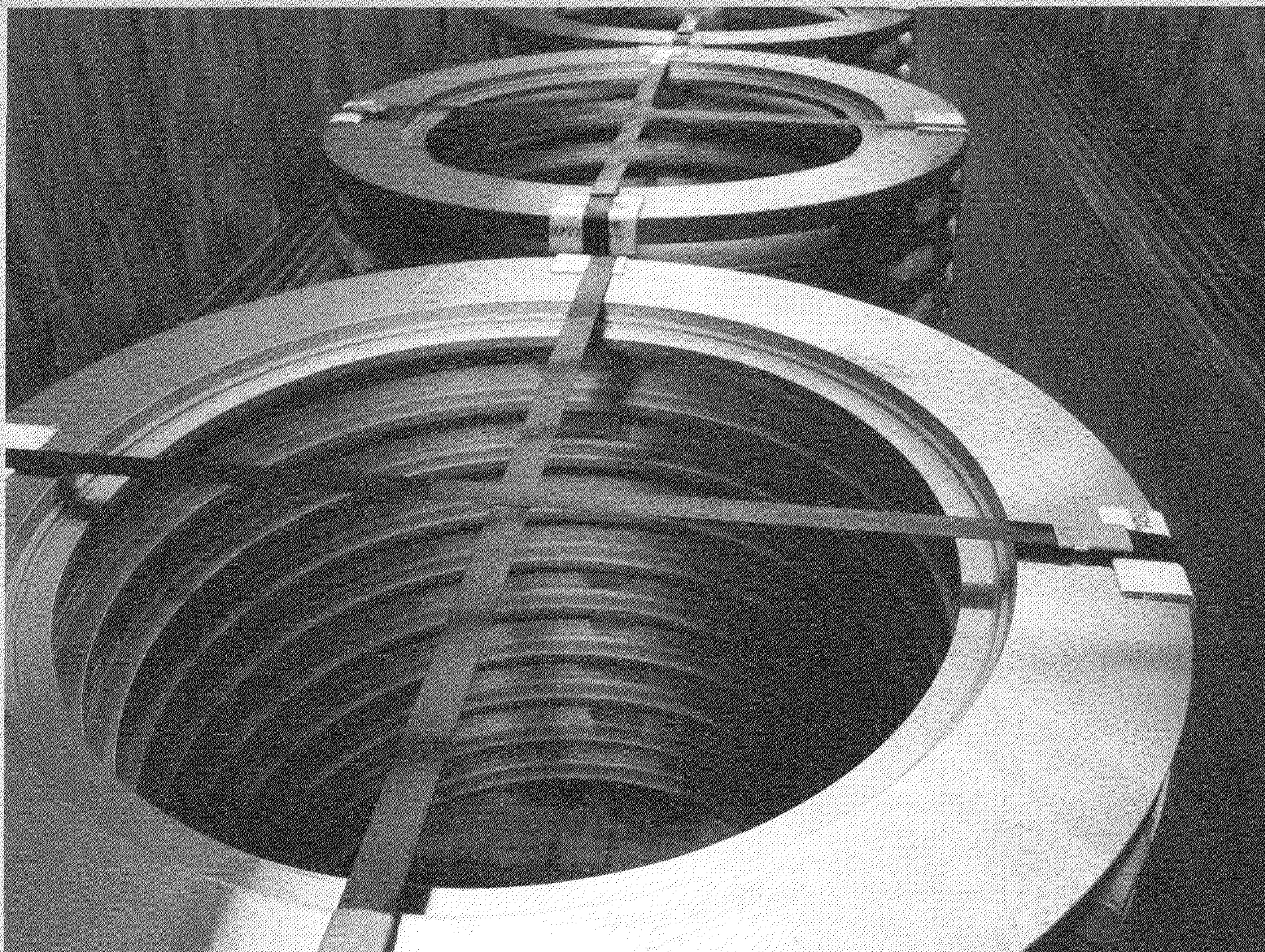
RATE CASES PURSUED IN EACH STATE

During 2008 Otter Tail Power Company pursued rate increases in each of the three states it serves. In July the Minnesota Public Utilities Commission granted the company a 2.9% increase, which is an annual revenue increase of approximately $3.8 million. The increase represents about one half of that requested in the rate case, which was filed in 2007.

In November the company filed for a rate increase in North Dakota, the first such filing since 1982. The company requested an increase of 5.1% over 2007, which would generate an additional $6.1 million in annual revenue if granted. The company began collecting interim rates in early 2009. A final decision on the North Dakota rate filing is expected by August 2009.

Otter Tail Power Company also filed for a South Dakota rate increase in October 2008, the first such filing since 1986. If approved, the new rates would add about $3.8 million to annual revenues, an increase of 15.3% over 2007. One of the primary drivers of this level in increase compared with the North Dakota and Minnesota filings is that cost recovery for the company's wind energy investment comes only through a rate case in South Dakota. North Dakota and Minnesota laws allow for cost recovery of renewable energy investment between rate cases. Both Minnesota and North Dakota granted recovery of Otter Tail Power Company's renewable energy costs in 2008. The South Dakota Public Utilities Commission is expected to rule on the rate request in mid-2009. Even after these increases Otter Tail Power Company's rates will remain among the lowest in the nation.

MANUFACTURING

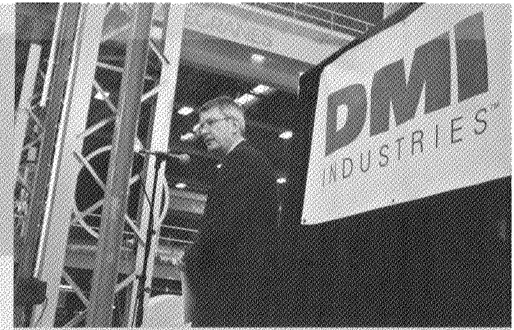


PRESSURE RELIEF PLATES FOR CATERPILLAR TRUCK BRAKING SYSTEMS ARE AMONG THE SPECIALTY PRODUCTS MANUFACTURED BY MILLER WELDING & IRON WORKS, A 2008 ACQUISITION BY BTD MANUFACTURING.

BTD EXPANDS

Living its motto of "Better Through Design," BTD Manufacturing, Inc. provides its customers a one-stop solution for design, engineering, prototyping and short-run functions, metal stamping, robotic and hand welding, spot welding, finishing machining, riveting, assembly, plating, heat treating and special packaging.

In May 2008 BTD acquired Miller Welding & Iron Works, Inc. of Washington, Illinois. With approximately 120 employees, Miller Welding provides BTD with additional geographic reach, new production capabilities and an expanded customer base.



DMI President Stefan Nilsson spoke at the Tulsa plant's ribbon-cutting ceremony. With three manufacturing facilities, DMI Manufacturing is strategically positioned in North America's premier wind resources areas.

In early 2009 BTD will double its footprint in the Minneapolis metro area by moving into a new leased facility. Together with its sister company T.O. Plastics, BTD will move into a 154,000-square-foot facility to meet the growing demand for its products and services. BTD's three locations in Minnesota now employ nearly 500 employees.

DMI INDUSTRIES EXPANDS CAPACITY IN WIND ENERGY MANUFACTURING

DMI Industries, Inc. is a diversified heavy steel manufacturer with a primary concentration on state-of-the-art wind tower manufacturing and assembly. With three strategically located facilities—West Fargo, North Dakota; Tulsa, Oklahoma; and Ft. Erie, Ontario, Canada—DMI has one of the largest wind energy tower manufacturing capacities in North America.

DMI spent much of 2008 bringing its new plant in Tulsa on line. The Tulsa site, acquired in August 2007, had shipped its first wind tower in mid-May 2008. And in June 2008 DMI launched additional expansion projects in West Fargo and Tulsa, which are expected to be completed and operational in early 2009.

This rapid expansion caused disappointing financial results in 2008. Although DMI had good operating results in its West Fargo plant, these results were masked by the costs of unanticipated delays and other difficulties in the construction and integration of the new production capabilities. While financial results in 2008 were disappointing, DMI is now well situated to respond to expected long term-growth prospects of the renewable energy industry.

SHOREMASTER HAS DIFFICULT YEAR

ShoreMaster, Inc. "covers the waterfront" with its industry-leading line of boat lifts and lift accessories, docks and dock accessories, marina systems and water toys.

Business conditions requiring consolidation of facilities and cost overruns at a large marina system construction project lead to disappointing performance in 2008. Given reduced demand, in May 2008 ShoreMaster closed its West Coast location and consolidated the West Coast operations into its location in Florida.

With difficult economic conditions continuing into 2009, ShoreMaster is focused on its sales efforts with innovative designs and continuing its efforts to operate more efficiently and effectively.

T.O. PLASTICS ADDS NEW PLANT

T.O. Plastics, Inc. manufactures extruded and thermoformed plastic products, including custom parts for customers in several industries and its own line of horticulture containers.

Founded over 60 years ago, T.O. Plastics has experienced impressive growth over the last five years. To continue this growth and meet customer demand efficiently and cost effectively, the company took steps in 2008 to consolidate operations and improve production capabilities.

In August 2008 T.O. Plastics sold its production facility in South Carolina. This allowed the company to better use resources and accommodated a move into a larger facility with its sister company BTD Manufacturing in the Minneapolis metro area. In this new location, which is expected to be fully operational in early 2009, the company will manufacture products from new in-line thermoforming equipment. In addition, the new location will allow T.O. Plastics to expand its "clean room" manufacturing of medical device and electronic component packaging.

INFRASTRUCTURE
PRODUCTS AND SERVICES

E.W. WYLIE CORPORATION IS AUGMENTING ITS CORE FLATBED BUSINESS WITH SPECIALIZED HEAVY-HAUL AND WIND TOWER TRANSPORT OPERATIONS.

PLASTICS COMPANIES ADAPT TO ECONOMY

Northern Pipe Products, Inc. and its sister company Vinyltech Corporation manufacture and sell PVC pipe used in municipal, rural and wastewater systems. Northern Pipe, located in Fargo, North Dakota, and Hampton, Iowa, serves customers primarily in the northern and midwestern regions of the United States and central and western Canada. Based in Phoenix, Arizona, Vinyltech serves customers primarily in the southwestern and western regions of the United States.

Midwest Construction Services' growth in electric transmission construction was driven, in part, by increased Upper Midwest wind development.

In June Northern Pipe's Hampton, Iowa, plant completed an expansion to manufacture larger pipe in diameters up to 27 inches. This positions the plastics companies to participate in additional projects that require larger-sized pipe. With the sudden drop in construction activity, Northern Pipe and Vinyltech saw reduced earnings as demand for their products declined. As economic conditions required, both companies have reduced output to match demand. The companies continue to work on projects to improve efficiencies of production and reduce costs of operation.

FOLEY COMPANY ACHIEVES RECORD RESULTS

Foley Company provides mechanical and prime contracting for water and wastewater treatment plants, hospital and pharmaceutical facilities, power plants and other large projects.

Located in Kansas City, Missouri, Foley Company celebrated its 95th anniversary with a successful 2008 and record revenues for a third year in a row. The company completed the mechanical HVAC and plumbing renovations at Kauffman Stadium, home of the Kansas City Royals.

In August 2008 Foley began work on the first phase of the Lewis & Clark Water Plant at Vermillion, South Dakota. The initial phase of the project includes site preparation, a high-service pump station and underground storage. The 45-million-gallon-per-day plant will serve residents in three states.

These projects and others led to record results for 2008 and provide a good foundation for 2009.

ELECTRIC TRANSMISSION AND WIND ENERGY PROJECTS DRIVE SUCCESS AT MCS

Midwest Construction Services, Inc. (MCS) offers a complete spectrum of electrical construction services. Headquartered in Moorhead, Minnesota, MCS's diversified services include aerial transmission and telecommunications facilities, overhead and underground utility lines, electrical substations, wind farm infrastructure and ethanol plant and other production systems.

Projects completed by the company in 2008 in North Dakota, South Dakota, Montana and Iowa boosted MCS's electrical transmission business volume by 40% compared to the previous year. The transmission growth was driven primarily by the increase in wind farm development in the Upper Midwest, one of the nation's leading wind energy resource areas. And its Ventus Energy Systems division continued to build on its reputation as a respected high-quality construction services firm for wind energy electric collector systems.

While current economic conditions will impact some projects in the short term, MCS has positioned itself well to respond to the energy infrastructure needs of the region.

E.W. WYLIE STARTS SPECIALIZED WIND ENERGY AND HEAVY-HAUL OPERATIONS

E.W. Wylie Corporation, with headquarters in West Fargo, North Dakota, and terminal locations in North Dakota, Minnesota, Texas and Colorado, is a flatbed contract and specialized contract and common carrier across the United States and Canada. To diversify its operations and to address the expected decline in other business opportunities, Wylie developed heavy-haul and wind energy transport operations in 2008. While Wylie's core flatbed business leveled off during the year due to the general decline in housing and construction starts, the new heavy-haul business grew quickly. The company added 45 tractor/trailer configurations, which can support loads of more than 120 tons and wind tower segments of up to 185 feet.

HEALTH SERVICES

Through mobile units, technologist Tena Scharmer with DMS Health Technologies provides full-view digital mammography for clients in small community hospitals and clinics where those services are not otherwise available.

HEALTH SERVICES PLATFORM REORGANIZES INTO A SINGLE CUSTOMER-FOCUSED BRAND

DMS Health Technologies, Inc. sells and services diagnostic imaging systems, new and reconditioned cardiac and patient monitoring systems and ultrasound equipment, along with parts, supplies and accessories. The company is also a leading provider of outsourced diagnostic imaging services.

DMS's equipment sales and service organization had solid results in 2008. Its imaging services business performed below expectations in 2008 as the imaging marketplace suffered from over-capacity and changes in the reimbursement regime for medical procedures.

At the start of 2009 DMS merged the brands of DMS Health Group, DMS Imaging and DMS Interim Solutions into a combined and energized DMS Health Technologies brand. This change was part of a strategy to align all of DMS's many products and services under a unified customer-based solutions focus.

FOOD INGREDIENT PROCESSING

IDAHO PACIFIC HOLDINGS RESULTS AFFECTED BY HIGH ENERGY COSTS

Idaho Pacific Holdings, Inc. headquartered in Ririe, Idaho, manufactures dehydrated potato products for the snack food, foodservice and bakery industries.

With plants strategically located in three different growing regions—Colorado, Idaho, and Prince Edward Island, Canada—Idaho Pacific offers its customers a unique source of supply by minimizing regional risks in crop production. In 2008 an unanticipated spike in energy costs and reduced raw material supplies dramatically impacted results.

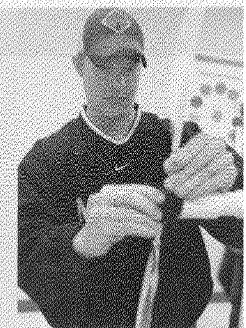
Refining its product mix will enable Idaho Pacific to meet strong domestic and international demand for dehydrated potato products.

COMMUNITY ENHANCEMENT AND ENVIRONMENTAL STEWARDSHIP ARE PRIORITIES AT OTTER TAIL CORPORATION

STEWARDSHIP

TEACHING TEACHERS ABOUT WIND ENERGY

DMI Industries, Inc. helped educate teachers about wind energy by again sponsoring a one-day KidWind Project workshop. St. Paul, Minnesota-based KidWind is made up of a team of teachers, students, engineers and practitioners who explore the science behind wind energy and train teachers to provide wind energy education in classrooms around the United States. The workshop provided about 20 Minnesota and North Dakota educators with background information about wind energy and gave them experience building classroom wind energy turbines, designing turbine blades and experimenting with other wind energy activities.

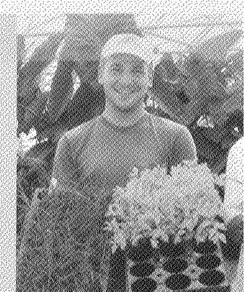


SERVING CUSTOMERS WITH RENEWABLE ENERGY

In 2008 Otter Tail Power Company completed its 48-megawatt ownership share of the Ashtabula Wind Center in eastern North Dakota. This is the third North Dakota wind farm from which the company acquires wind-generated electricity. Otter Tail Power Company is a national leader among utilities in the percentage of electric plant invested in wind energy. In addition, the company has a strong commitment to energy efficiency and demand-side management. These renewable energy and energy-efficiency investments are consistent with the company's mission of delivering reliable, affordable electricity in a manner that demonstrates environmental stewardship.

RECYCLING CONTAINERS FOR NEW GROWTH

T.O. Plastics, Inc. manufactures a variety of horticulture containers from 100% recycled materials. The company thermoforms its own sheet and roll stock from resins that have had a previous life. In addition, all scrap by-products are remade into more roll stock, resulting in a complete closed-loop system that produces no waste. T.O. Plastics uses minimal packaging and constantly seeks maximum storage and shipping efficiencies. All of the company's products are stamped with a recycle code to alert the end-user to recycle them once more.



MAKING A DIFFERENCE WITH COMMUNITY ACTION

Northeast South Dakota Community Action Program promotes community excellence through housing programs, energy assistance and energy efficiency and conservation training. Northeast South Dakota Economic Corporation stimulates economic opportunities through loans, technical assistance and partnership with individuals and businesses. In recognition of the collaborative nature of these organizations and the benefits they bring to Otter Tail Power Company's service area in South Dakota, Otter Tail Power Company provided technology and furnishings for much-needed meeting rooms in Sisseton. As part of its centennial celebration, Otter Tail Power Company is initiating "pay-it-forward" projects such as this in each of the three states it serves.

STEWARDSHIP

DETECTING CANCER EARLY WITH CUTTING-EDGE MAMMOGRAPHY SERVICES

Through mobile units, DMS Health Technologies, Inc. is bringing full-field digital mammography to women across the region. Images are electronically transmitted to radiologists in larger medical centers where they can view and manipulate the images and enhance visualization of structures within the breast. Digital mammography is superior to traditional film-based exams and allows radiologists to detect small masses that might be the early stages of cancer. DMS is giving rural facilities the ability to offer women the highest quality cutting-edge care without having to invest in capital equipment.

USING FLY ASH TO BENEFIT FARMERS AND THE ENVIRONMENT

The Minnesota Pollution Control Agency approved fly ash from Otter Tail Power Company's Hoot Lake Plant for use in feedlots, private farm roads, agricultural produce storage pads and cattle-working areas. Fly ash can stabilize soil, reduce mud and allow for easier removal of manure. Using this versatile material offers several environmental advantages. Each ton of fly ash used in agricultural applications is a ton that does not have to be stored at the plant site. In addition, the use of fly ash helps impede agricultural runoff.

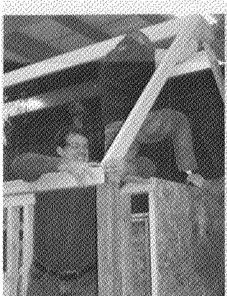


Photo by Pippi Mayfield

BUILDING A PLAYHOUSE WHILE BUILDING CHARACTER

BTD Manufacturing, Inc. hosted members of an Otter Tail Corporation leadership program to build a playhouse in Detroit Lakes, Minnesota. About 25 Otter Tail employees from across the country worked for several hours until the project was completed. The playhouse will be raffled off as a fund-raiser by the Boys and Girls Club of Detroit Lakes. The project is one element of instilling a commitment to community service in employees who are or may become company leaders.

EARNING A PAYCHECK

In 2008 T.O. Plastics, Inc. continued to partner with Achieve Services and Options, Incorporated to help people with disabilities in the Twin Cities earn a paycheck. Achieve Services and Options' employees apply customer-specific bar code labels to many of the horticulture containers T.O. Plastics produces. The labeling process allows T.O. Plastics' production staff to be more effective in expediting deliveries to customers. The work gives Achieve's employees an opportunity to contribute to the community with excellent service and with the satisfaction of being gainfully employed.

CREATING AND RETAINING JOBS

Otter Tail Power Company's on-staff economic development professionals, such as Don Frye in North Dakota, take pride in helping communities and businesses evolve. They offer services related to financing strategy, partnership development, labor need/development assessment and more. Through these efforts Otter Tail Power Company has helped create more than 18,210 jobs and save nearly 3,875 jobs since 1989.

FINANCIAL REVIEW

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands, except number of shareholders and per-share data)	2008	2007	2006	2005	2004	2003	1998(4)
Revenues							
Electric	**$ 340,020**	$ 323,478	$ 306,014	$ 312,985	$ 266,385	$ 267,494	$ 206,895
Plastics	**116,452**	149,012	163,135	158,548	115,426	86,009	24,946
Manufacturing	**470,462**	381,599	311,811	244,311	201,615	157,401	53,709
Health Services	**122,520**	130,670	135,051	123,991	114,318	100,912	69,412
Food Ingredient Processing	**65,367**	70,440	45,084	38,501	14,023	—	—
Other Business Operations (1)	**199,511**	185,730	145,603	105,821	102,516	78,094	36,115
Corporate Revenues and Intersegment Eliminations (1)	**(3,135)**	(2,042)	(1,744)	(2,288)	(1,247)	(921)	—
Total Operating Revenues	**$ 1,311,197**	$1,238,887	$1,104,954	$ 981,869	$ 813,036	$ 688,989	$ 391,077
Special Charges	**—**	—	—	—	—	—	9,522
Net Income from Continuing Operations	**35,125**	53,961	50,750	53,902	40,502	38,297	29,167
Net Income from Discontinued Operations	**—**	—	362	8,649	1,693	1,359	1,534
Net Income	**35,125**	53,961	51,112	62,551	42,195	39,656	30,701
Cumulative Change in Accounting Principle	**—**	—	—	—	—	—	3,819
Operating Cash Flow from Continuing Operations	**111,321**	84,812	79,207	90,348	54,410	76,464	60,985
Operating Cash Flow—							
Continuing and Discontinued Operations	**111,321**	84,812	80,246	95,800	56,301	76,955	63,959
Capital Expenditures—Continuing Operations	**265,888**	161,985	69,448	59,969	49,484	48,783	27,740
Total Assets	**1,692,587**	1,454,754	1,258,650	1,181,496	1,134,148	986,423	690,189
Long-Term Debt	**339,726**	342,694	255,436	258,260	261,805	262,311	172,080
Redeemable Preferred	**—**	—	—	—	—	—	18,000
Basic Earnings Per Share—Continuing Operations (2)	**1.09**	1.79	1.70	1.82	1.53	1.47	1.14
Basic Earnings Per Share—Total (2)	**1.09**	1.79	1.71	2.12	1.59	1.52	1.20
Diluted Earnings Per Share—Continuing Operations (2)	**1.09**	1.78	1.69	1.81	1.52	1.46	1.14
Diluted Earnings Per Share—Total (2)	**1.09**	1.78	1.70	2.11	1.58	1.51	1.20
Return on Average Common Equity	**6.0%**	10.5%	10.6%	13.9%	12.0%	12.2%	15.0%
Dividends Per Common Share	**1.19**	1.17	1.15	1.12	1.10	1.08	0.96
Dividend Payout Ratio	**109%**	66%	68%	53%	70%	72%	71%
Common Shares Outstanding—Year End	**35,385**	29,850	29,522	29,401	28,977	25,724	23,759
Number of Common Shareholders (3)	**14,627**	14,509	14,692	14,801	14,889	14,723	13,699

Notes: (1) Beginning in 2007 corporate revenues and expenses are no longer reported as components of Other Business Operations. Prior years have been restated accordingly.
(2) Based on average number of shares outstanding.
(3) Holders of record at year end.
(4) In the first quarter of 1998 the Company changed its method of electric revenue recognition in the states of Minnesota and South Dakota from meter-reading dates to energy-delivery dates. Basic and diluted earnings per share from continuing operations does not include 16 cents per share related to the cumulative effect of the change in accounting principle.

SELECTED ELECTRIC OPERATING DATA

	2008	2007	2006	2005	2004	2003	1998
Revenues (thousands)							
Residential	**$ 97,567**	$ 92,254	$ 86,950	$ 83,740	$ 76,365	$ 75,689	$ 64,430
Commercial and Farms	**113,307**	111,960	101,895	100,677	88,853	88,550	74,215
Industrial	**74,879**	68,648	65,370	61,235	54,159	48,315	43,426
Sales for Resale	**27,236**	25,640	25,965	46,397	27,228	29,702	8,460
Other Electric	**27,031**	24,976	25,834	20,936	19,780	25,238	16,364
Total Electric	**$ 340,020**	$ 323,478	$ 306,014	$ 312,985	$ 266,385	$ 267,494	$ 206,895
Kilowatt-Hours Sold (thousands)							
Residential	**1,257,641**	1,218,026	1,170,841	1,162,765	1,119,067	1,141,612	1,020,471
Commercial and Farms	**1,576,230**	1,515,635	1,453,664	1,428,059	1,386,358	1,396,638	1,241,529
Industrial	**1,339,726**	1,321,249	1,297,287	1,233,948	1,197,534	1,108,021	1,144,025
Other	**68,310**	68,921	69,062	69,663	70,105	70,071	66,393
Total Retail	**4,241,907**	4,123,831	3,990,854	3,894,435	3,773,064	3,716,342	3,472,418
Sales for Resale	**2,682,629**	1,648,841	2,778,460	2,778,431	3,845,299	3,786,397	1,183,552
Total	**6,924,536**	5,772,672	6,769,314	6,672,866	7,618,363	7,502,739	4,655,970
Annual Retail Kilowatt-Hour Sales Growth	**2.9%**	3.3%	2.5%	3.2%	1.5%	0.7%	(0.3)%
Heating Degree Days	**9,752**	9,050	8,260	8,656	9,132	9,132	8,173
Cooling Degree Days	**330**	482	517	423	228	515	533
Average Revenue Per Kilowatt-Hour							
Residential	**7.76¢**	7.57¢	7.43¢	7.20¢	6.82¢	6.63¢	6.31¢
Commercial and Farms	**7.19¢**	7.39¢	7.01¢	7.05¢	6.41¢	6.34¢	5.98¢
Industrial	**5.59¢**	5.20¢	5.04¢	4.96¢	4.52¢	4.36¢	3.80¢
All Retail	**6.78¢**	6.71¢	6.54¢	6.39¢	5.95¢	5.85¢	5.39¢
Customers							
Residential	**101,600**	101,750	101,657	101,176	100,952	100,515	98,849
Commercial and Farms	**26,557**	26,500	26,343	26,211	26,157	25,900	25,777
Industrial	**42**	42	42	44	40	40	37
Other	**1,069**	1,050	1,028	1,035	1,069	1,079	1,049
Total Electric Customers	**129,268**	129,342	129,070	128,466	128,218	127,534	125,712
Residential Sales							
Average Kilowatt-Hours Per Customer (5)	**12,449**	12,100	11,706	11,749	11,251	11,525	10,492
Average Revenue Per Residential Customer	**$ 976.37**	$ 893.01	$ 862.99	$ 776.48	$ 766.99	$ 756.83	$ 662.44

Notes: (5) Based on average number of customers during the year.

OVERVIEW

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

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

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

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

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

The following major events occurred in our company in 2008:

- We achieved record annual consolidated revenues of $1.3 billion.
- We achieved record annual net cash from operations of $111.3 million.
- Net income from our electric segment was $33.2 million.
- Our construction companies reported record net income of $5.5 million.
- Capital expenditures totaled $266 million, including expenditures for the electric utility's 32 wind turbines at the Ashtabula Wind Center in Barnes County, North Dakota and expansion of the wind tower manufacturing facilities of DMI Industries, Inc. (DMI) in West Fargo, North Dakota and Tulsa, Oklahoma.
- On May 1, 2008 BTD Manufacturing, Inc. (BTD) acquired the assets of Miller Welding & Iron Works, Inc. (Miller Welding), of Washington, Illinois for $41.7 million in cash.
- The electric utility was granted a general rate increase of 2.9% in Minnesota and regulators in both Minnesota and North Dakota approved rate riders for the recovery of renewable resource costs and investment returns.
- The electric utility filed a general rate case in North Dakota in November 2008 requesting a revenue increase of approximately $6.1 million.
- The electric utility filed a general rate case in South Dakota in October 2008 requesting a revenue increase of approximately $3.8 million.

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

- Planned capital budget expenditures of up to $884 million for the years 2009-2013 of which $698 million is for capital projects at the electric utility, including $395 million related to Big Stone II and associated transmission projects and $66 million for anticipated expansion of transmission capacity in Minnesota (CapX 2020). See "Capital Requirements" section for further discussion.
- Pursuing the regulatory approvals, financing and other arrangements necessary to build Big Stone II.
- Adding more renewable resources to our electric resource mix.
- Completion of the North Dakota and South Dakota general rate cases.
- The continued investigation and evaluation of organic growth and strategic acquisition opportunities.

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

(in thousands)	**2008**	2007
Operating Revenues:		
Electric	**$ 339,726**	$ 323,158
Nonelectric	**971,471**	915,729
Total Operating Revenues	**$ 1,311,197**	$ 1,238,887
Net Income:		
Electric	**$ 33,234**	$ 24,498
Nonelectric	**1,891**	29,463
Total Net Income	**$ 35,125**	$ 53,961

The 5.8% increase in consolidated revenues in 2008 compared with 2007 reflects significant revenue growth from our manufacturing and electric segments. Revenues increased $88.9 million in our manufacturing segment in 2008 mainly due to increased sales of wind towers and other fabricated steel products, including $17.5 million related to the acquisition of Miller Welding in May 2008. Electric segment revenues grew by $16.6 million as a result of increases in retail and wholesale kilowatt-hour (kwh) sales, a 2.9% general rate increase in Minnesota, initiation of renewable resource recovery riders in North Dakota and Minnesota and an increase in contracted electrical construction work performed for other entities. Revenues at our transportation company increased $7.5 million as a result of passing through higher fuel costs and the introduction of heavy-haul and wind tower transport services. Our construction companies' revenues grew by $6.3 million in 2008 as higher backlog going into 2008 resulted in an increase in volume of jobs in progress. Revenues decreased by $32.6 million in our plastics segment in 2008 as a result of lower volumes of pipe sold due to a decrease in construction activity related to the current economic downturn. Revenues from our health services segment decreased $8.1 million in 2008, reflecting a shift from traditional dealership distribution of products to more commission-based compensation for sales. Food ingredient processing revenues decreased $5.1 million as a result of a 13.2% decrease in pounds of products sold in 2008.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2008, 2007 and 2006, followed by our outlook for 2009, a discussion of our financial position at the end of 2008 and risk factors that may affect our future operating results and financial position.

RESULTS OF OPERATIONS

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

Amounts presented in the following segment tables for 2008, 2007 and 2006 operating revenues, cost of goods sold and other nonelectric operating expenses will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	**2008**	2007	2006
Operating Revenues:			
Electric	$ 294	$ 320	$ 311
Nonelectric	2,841	1,722	1,433
Cost of Goods Sold	2,703	1,553	1,433
Other Nonelectric Expenses	432	489	311

ELECTRIC

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

(in thousands)	**2008**	**% change**	2007	% change	2006
Retail Sales Revenues	$ 287,631	4	$ 276,894	6	$ 260,926
Wholesale Revenues	25,122	13	22,306	(13)	25,514
Net Marked-to-Market Gains	2,114	(37)	3,334	639	451
Other Revenues	25,153	20	20,944	10	19,123
Total Operating Revenues	$ 340,020	5	$ 323,478	6	$ 306,014
Production Fuel	71,930	19	60,482	3	58,729
Purchased Power—System Use	56,329	(25)	74,690	28	58,281
Other Operation and Maintenance Expenses	115,300	8	107,041	3	103,548
Depreciation and Amortization	31,755	22	26,097	1	25,756
Property Taxes	8,949	(5)	9,413	(2)	9,589
Operating Income	$ 55,757	22	$ 45,755	(9)	$ 50,111

2008 compared with 2007

The $10.7 million increase in retail electric sales revenues in 2008 compared with 2007 reflects $8.0 million in 2008 Minnesota and North Dakota renewable resource cost recovery rider revenue and an approved increase in Minnesota retail electric rates of approximately 2.9% that resulted in a $3.6 million increase in retail revenues in 2008. These revenue increases were augmented by an additional $5.8 million in revenue mainly related to a 2.9% increase in retail kwh sales resulting from load growth and a 7.8% increase in heating degree days between the years. These increases in retail sales revenues were offset by a $6.7 million reduction in fuel clause adjustment (FCA) revenues related to a reduction in kwhs purchased for system use in 2008.

Wholesale electric revenues from company-owned generation increased to $23.7 million in 2008 compared with $20.3 million in 2007 as a result of a 28.4% increase in wholesale kwh sales, partially offset by a 9.2% decrease in the price per kwh sold. Greater plant availability in 2008 provided the electric utility with more opportunities to respond to wholesale market demands. Net gains from energy trading activities, including net mark-to-market gains and losses on forward energy contracts, were $3.5 million in 2008 compared with $5.3 million in 2007 as a result of a decrease in volume of forward energy purchase and sales contracts entered into by the electric utility in 2008.

The increase in other electric revenues includes a $3.6 million increase in revenues from contracted construction work completed for other entities on regional wind power projects and a $0.8 million increase in revenues from steam sales to an ethanol plant near the Big Stone Plant site, offset by a $0.2 million reduction in revenues from shared use of transmission facilities.

Fuel and purchased-power costs to serve retail and wholesale electric customers decreased $6.9 million between the years. Fuel costs for generation for retail customers increased $8.3 million as a result of a 12.1% increase in generation for system use combined with a 3.4% increase in fuel costs per kwh generated for system use. Purchased power costs to serve retail customers decreased $18.4 million as a result of a 23.8% decrease in kwhs purchased combined with a 1.0% decrease in the cost per kwh purchased for system use. Fuel costs for wholesale sales increased $3.2 million due to a 28.4% increase in wholesale kwh sales combined with a 7.1% increase in the cost of fuel per kwh generated for wholesale sales. Overall fuel-fired kwh generation increased 9.3% as a result of greater plant availability in 2008. Fuel costs per kwh generated increased 8.8%, but kwhs generated from zero-fuel-cost wind turbines mitigated the increase in fuel costs per kwh from generation used to serve retail customers.

The $8.3 million increase in electric operating and maintenance expenses includes: (1) $3.1 million in increased material costs not subject to recovery through retail rates, related to contracted construction work completed for other entities on regional wind power projects, (2) $1.7 million in turbine repair costs at Hoot Lake Plant in 2008, (3) $0.9 million in higher wage and benefit expenses related to a general wage increase, (4) $0.6 million in wind turbine related expenses, and (5) a net increase of $2.0 million in other operating expenses. The $5.7 million increase in depreciation and amortization expense is due to recent capital additions, including 27 wind turbines at the Langdon Wind Energy Center that were built in 2007. Property tax expense decreased $0.5 million as a result of decreases in utility property assessed values in Minnesota and South Dakota and changes in assessment methodology in South Dakota.

2007 compared with 2006

The $16.0 million increase in retail electric sales revenues in 2007 compared with 2006 includes a net increase of $8.4 million in FCA revenues mainly related to an increase in purchased power costs in the fourth quarter of 2007 to replace generation lost during a scheduled major maintenance shutdown of our Big Stone Plant. The increase in retail revenues also includes $7.6 million related to a 3.3% increase in retail kwh sales. Residential kwh sales increased 4.0% due, in part, to a 9.6% increase in heating degree days. Increased oil and ethanol production in our electric service territory and surrounding regions contributed to a 3.1% increase in commercial and industrial kwh sales. The increase in FCA revenues related to increases in fuel and purchased power costs for system use between the years was $14.4 million. The $8.4 million net increase in FCA revenues includes the effects of $6.0 million in FCA adjustments and refunds in 2006 and 2007 that were not related to increases in fuel and purchased power costs between the years.

A 30.6% decline in wholesale kwh sales from company-owned generation in 2007 compared with 2006 resulted in a $2.8 million decrease in wholesale revenues despite a 26.7% increase in the price per kwh sold from company-owned generating units. In 2006, advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006, when the weather was unseasonably mild. Advance purchases of electricity in anticipation of coal supply constraints at Big Stone and Hoot Lake plants in the second quarter of 2006 freed up more generation for wholesale sales when coal supplies improved in May 2006. Net revenues from energy trading activities, including net mark-to-market gains on forward energy contracts, were $5.3 million in 2007 compared with $2.8 million in 2006. The $2.5 million increase in revenue from energy trading activities reflects a $3.5 million increase in profits from purchased power resold and net settlements of forward energy contracts and a $2.9 million increase in net mark-to-market gains on forward energy contracts, offset by a $3.9 million decrease in profits related to the purchase and sale of financial transmission rights.

The $1.8 million increase in other electric operating revenues in 2007 compared with 2006 is related to increases in revenues of $0.8 million from electric system planning and construction work performed for other companies, $0.5 million from integrated transmission agreements and $0.4 million for reimbursement of system operations costs from the Midwest Independent Transmission System Operator (MISO).

The $1.8 million increase in fuel costs in 2007 compared with 2006 reflects an 8.7% increase in the cost of fuel per kwh generated offset by a 5.3% decrease in kwhs generated. Generation used for wholesale electric sales decreased 30.6% while generation for retail sales decreased 0.8% between the years. Fuel costs for the electric utility's combustion turbines increased $2.0 million due to an 86.1% increase in kwhs generated from those units. Fuel costs per kwh increased at all of the electric utility's steam turbine generating units as a result of increases in coal and coal transportation costs between the years. Much of the increase in coal and coal transportation costs is related to higher diesel fuel prices.

The $16.4 million increase in purchased power—system use (to serve retail customers) in 2007 compared with 2006 is due to a 22.1% increase in kwh purchases for system use combined with a 4.9% increase in the cost per kwh purchased. The increase in kwh purchases was a result of power purchased to replace generation lost during the scheduled major maintenance shutdown of our Big Stone Plant in the fourth quarter of 2007.

The $3.5 million increase in other operation and maintenance expenses for 2007 compared with 2006 includes increases of: (1) $1.1 million in labor and benefit costs related to wage and salary increases averaging approximately 3.8% and an increase in employee numbers between the periods, (2) $1.0 million in costs related to contracted construction work performed for other companies, (3) $0.7 million in external costs related to rate case preparation and (4) $0.6 million in tree-trimming expenditures.

PLASTICS

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

(in thousands)	**2008**	**% change**	2007	% change	2006
Operating Revenues	**$ 116,452**	**(22)**	$ 149,012	(9)	$ 163,135
Cost of Goods Sold	**104,186**	**(16)**	124,344	(2)	126,374
Operating Expenses	**4,956**	**(31)**	7,223	(29)	10,239
Depreciation and Amortization	**3,050**	**(1)**	3,083	10	2,815
Operating Income	**$ 4,260**	**(70)**	$ 14,362	(39)	$ 23,707

2008 compared with 2007

The $32.6 million decrease in plastics operating revenues in 2008 compared with 2007 reflects a 26.2% decrease in pounds of pipe sold, partially offset by a 5.9% increase in the price per pound of pipe sold. The decrease in pounds of pipe sold is due to sluggish housing and construction markets in 2008. The $2.3 million decrease in plastics segment operating expenses is mostly due to decreases in employee incentives and sales commissions directly related to the decreases in pipe sales and operating margins between the years, but also reflects reductions in bad debt and property tax expenses.

2007 compared with 2006

The $14.1 million decrease in plastics operating revenues in 2007 compared with 2006 reflects an 18.8% decrease in the price per pound of pipe sold, partially offset by a 12.5% increase in pounds of pipe sold. The decrease in pipe prices and cost of goods sold reflects the effect of a 15.7% decrease in polyvinyl chloride (PVC) resin prices between the years. The $3.0 million decrease in plastics segment operating expenses reflects a decrease in employee incentives directly related to the decreases in operating margins between the years. The increase in depreciation and amortization expense is the result of $5.5 million in capital additions in 2006, mainly for production equipment.

MANUFACTURING

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

(in thousands)	**2008**	**% change**	2007	% change	2006
Operating Revenues	**$ 470,462**	**23**	$ 381,599	22	$ 311,811
Cost of Goods Sold	**389,060**	**30**	300,146	22	246,649
Operating Expenses	**44,093**	**25**	35,278	33	26,508
Plant Closure Costs	**2,295**	**—**	—	—	—
Depreciation and Amortization	**19,260**	**47**	13,124	18	11,076
Operating Income	**$ 15,754**	**(52)**	$ 33,051	20	$ 27,578

2008 compared with 2007

The increase in revenues in our manufacturing segment in 2008 compared with 2007 relates to the following:

- Revenues at DMI increased $64.6 million (35.0%) as a result of increases in production and sales activity, including first-year production from its new plant in Oklahoma.
- Revenues at BTD increased $32.0 million (39.0%) between the years, including $17.5 million in 2008 revenues from Miller Welding, acquired in May 2008, $7.6 million from higher prices driven by higher material costs and $6.9 million from increased sales to existing customers.
- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased $2.5 million (6.5%) between the years as a result of increased sales of horticultural products.
- Revenues at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment manufacturer, decreased $10.3 million (13.5%) between the years as a result of lower residential and commercial sales.

The increase in cost of goods sold in our manufacturing segment in 2008 compared with 2007 relates to the following:

- Cost of goods sold at DMI increased $63.7 million between the years as a result of increases in production and sales activity, including initial operations at its new plant in Oklahoma. DMI experienced only a $0.9 million increase in gross profit margins between the years mainly due to the start-up of its Oklahoma plant, where the levels of labor and overhead spending have been higher than expected and production has not reached levels necessary to cover these costs. Included in cost of goods sold for 2008 are costs of $4.3 million associated with start-up of the Oklahoma plant, $3.5 million in additional labor and material costs on a production contract at the Ft. Erie plant and higher costs due to steel surcharges.
- Cost of goods sold at BTD increased $23.4 million between the years, mainly in the categories of materials, labor and shop supply costs, as a result of increased sales volumes to existing customers and higher material prices. Miller Welding accounted for $13.2 million of the increase in cost of goods sold. BTD's gross margin was also reduced by $1.0 million in 2008 as a result of the sale of Miller Welding's inventory that was adjusted to fair value on acquisition, as required under business combination accounting rules.
- Cost of goods sold at T.O. Plastics increased $2.2 million, mainly in material costs related to increased sales of horticultural products.
- Cost of goods sold at ShoreMaster decreased by $0.3 million despite a $10.3 million decrease in revenues between the years. Reduced sales combined with dealer discounts and tighter profit margins, as well as losses incurred on a large marina project in Costa Rica, contributed to the $10.0 million decline in gross profits at ShoreMaster.

The increase in operating expenses in our manufacturing segment in 2008 compared with 2007 relates to the following:

- Operating expenses at DMI increased $5.3 million, including expenses related to the operation of its new plant in Oklahoma, which began construction in the third quarter of 2007 and went into operation in

January 2008. The increase also includes approximately $1.0 million in increased severance and retention costs in 2008 related to personnel changes and delayed orders for towers that resulted in workforce reductions at the end of 2008.
- Operating expenses at BTD increased $3.6 million between the years, mainly as a result of increases in labor, benefit and contracted service expenses and the May 2008 acquisition of Miller Welding.
- Operating expenses at T.O. Plastics decreased by $0.1 million, but T.O. Plastics operating income was flat between the years as its depreciation expenses increased by $0.4 million related to $7.0 million in capital expenditures in 2007 and 2008.
- Operating expenses at ShoreMaster increased $2.3 million as a result of the shutdown and sale of ShoreMaster's production facility in California following the completion of a major marina project in the state. Plant closure costs include employee-related termination obligations, asset impairment costs plus other related losses and expenses.

Depreciation and amortization expense increased mainly as a result of capital additions at DMI and T.O. Plastics and the May 2008 acquisition of Miller Welding.

Segment operating income decreased by $17.3 million primarily due to a $12.3 million decline in operating income at ShoreMaster.

2007 compared with 2006

The increase in revenues in our manufacturing segment in 2007 compared with 2006 relates to the following:
- Revenues at DMI increased $48.0 million (35.2%) as a result of increased productivity at the West Fargo plant and increased production levels at the Ft. Erie plant compared with initial start-up levels beginning in May 2006.
- Revenues at ShoreMaster increased $15.9 million (26.4%) between the years due to increased production and sales of commercial products and higher residential sales during the peak selling season. The Aviva Sports product line, acquired by ShoreMaster in February 2007, contributed $3.7 million to the increase in revenues.
- Revenues at BTD increased $3.5 million (4.5%) between the years, mainly as a result of the May 2007 acquisition of Pro Engineering, LLC (Pro Engineering).
- Revenues at T.O. Plastics increased $2.4 million (6.4%) between the years as a result of greater demand for both custom and horticultural products.

The increase in cost of goods sold in our manufacturing segment in 2007 compared with 2006 relates to the following:
- Cost of goods sold at DMI increased $39.8 million between the years, including increases of $30.4 million in material and supplies, $6.8 million in labor and benefit costs and $2.6 million in other direct manufacturing costs. The increase in cost of goods sold is directly related to DMI's increase in production and sales activity, including operations at the Ft. Erie facilities which commenced in May 2006.
- Cost of goods sold at ShoreMaster increased $9.2 million between the years as a result of increases in material and labor costs directly related to the increase in commercial and residential product sales as well as the acquisition of the Aviva Sports product line in February 2007, which contributed $2.9 million to cost of goods sold in 2007.
- Cost of goods sold at BTD increased $2.8 million between the years as a result of the acquisition of Pro Engineering in May 2007, partially offset by a decrease in costs at BTD's other manufacturing facilities related to a decrease in unit sales between the years.
- Cost of goods sold at T.O. Plastics increased $2.1 million, mainly driven by an increase in volume, as compared to 2006, and higher material costs.

The increase in operating expenses in our manufacturing segment in 2007 compared with 2006 relates to the following:
- Operating expenses at DMI increased $3.0 million, including $2.0 million in 2007 pre-production start-up costs at its new plant in Oklahoma and increases in expenses related to full operations at the Ft. Erie facility. The new plant in Oklahoma started producing towers in January 2008.
- Operating expenses at ShoreMaster increased $3.9 million as a result of increases in labor, benefits, sales expenses and professional services, of which $1.7 million is related to the Aviva Sports product line acquired in February 2007 and $1.3 million is related to facility relocation and legal expenses.
- Operating expenses at BTD increased $1.3 million between the years as a result of increases in labor and other expenses, mainly related to the acquisition of Pro Engineering in May 2007, and the reduction of a legal settlement reserve in 2006.
- Operating expenses at T.O. Plastics increased by $0.6 million between the years mainly as a result of leadership succession costs and increases in professional service expenditures.

Depreciation expense increased between the years mainly as a result of 2006 capital additions at DMI's Ft. Erie and West Fargo plants.

HEALTH SERVICES

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

(in thousands)	**2008**	**% change**	2007	% change	2006
Operating Revenues	**$ 122,520**	**(6)**	$ 130,670	(3)	$ 135,051
Cost of Goods Sold	**96,349**	**(3)**	99,612	(4)	104,108
Operating Expenses	**21,030**	**(11)**	23,691	4	22,745
Depreciation and Amortization	**4,133**	**5**	3,937	8	3,660
Operating Income	**$ 1,008**	**(71)**	$ 3,430	(24)	$ 4,538

2008 compared with 2007

The $8.2 million decrease in health services operating revenues in 2008 compared with 2007 reflects a $4.6 million decrease in revenues from scanning and other related services as a result of a decrease in revenues from rental and interim installations. Revenues from equipment sales and servicing decreased $3.6 million and cost of goods sold decreased $3.3 million between the years as a decrease in traditional dealership distribution of products was mostly offset by increases in manufacturer representative commissions on more manufacturer-direct sales. The $2.7 million decrease in operating expenses includes a $0.9 million increase in gains on sales of imaging company assets, reductions in sales, marketing and advertising expenses totaling $1.2 million and a $0.4 million decrease in labor costs. The increase in depreciation and amortization expense is due to capital additions in 2007 and 2008. The imaging side of the business continues to be affected by less than optimal utilization of certain imaging assets.

2007 compared with 2006

The $4.4 million decrease in health services operating revenues in 2007 compared with 2006 reflects a $3.2 million decrease in revenues from scanning and other related services as a result of a $2.8 million decrease in revenues from rental and interim installations and transportation services and a 9.2% decrease in the number of scans performed between the years. Revenues from equipment sales and servicing decreased $1.2 million between the years as a decrease in traditional dealership distribution of products was mostly offset by increases in manufacturer representative commissions on more manufacturer-direct sales. The decrease in health services revenue was more than offset by the decrease in health services cost of goods sold due to the decrease in traditional dealership distribution of products and $3.2 million in decreases to labor, warranty and other direct costs of sales. The $0.9 million increase in operating expenses is mainly due to increased labor and sales and marketing expenditures. The increase in depreciation and amortization expense is due to capital additions in 2006 and 2007.

FOOD INGREDIENT PROCESSING

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

(in thousands)	2008	% change	2007	% change	2006
Operating Revenues	$ 65,367	(7)	$ 70,440	56	$ 45,084
Cost of Goods Sold	55,415	(2)	56,591	28	44,233
Operating Expenses	2,998	(4)	3,135	7	2,920
Depreciation and Amortization	4,094	4	3,952	5	3,759
Operating Income (Loss)	$ 2,860	(58)	$ 6,762	216	$ (5,828)

2008 compared with 2007

The $5.1 million decrease in food ingredient processing revenues in 2008 compared with 2007 is due to a 13.2% decrease in pounds of product sold, partially offset by a 7.0% increase in the price per pound of product sold. The decrease in product sales was due to a reduction in sales to European customers and major snack customers and to lower production caused by potato supply shortages. European sales were higher than normal in 2007 due to reduced crop yields in Europe in 2006. Supply constraints combined with energy costs rising at rates faster than could be passed through to customers increased costs and lowered profits on products sold in 2008.

2007 compared with 2006

The $25.4 million increase in food ingredient processing revenues in 2007 compared with 2006 reflects a 29.5% increase in pounds of product sold combined with a 20.7% increase in the price per pound sold. A reduction in the value of the U.S. dollar relative to certain foreign currencies in 2007 and a poor European potato crop in 2006 led to favorable export pricing and sales increases in Europe, Latin America and the Pacific Rim in 2007. The increase in revenues was only partially offset by a 27.9% increase in cost of goods sold. The cost per pound of product sold decreased 1.2% between the years. The increase in operating expenses between the years is mainly due to increases in employee benefit and travel expenses. The increase in depreciation and amortization expense is related to $1.8 million in capital additions in 2006.

OTHER BUSINESS OPERATIONS

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

(in thousands)	2008	% change	2007	% change	2006
Operating Revenues	$ 199,511	7	$ 185,730	28	$ 145,603
Cost of Goods Sold	132,985	—	133,407	45	91,806
Operating Expenses	54,538	28	42,448	1	41,867
Depreciation and Amortization	2,230	8	2,058	(12)	2,330
Operating Income	$ 9,758	25	$ 7,817	(19)	$ 9,600

2008 compared with 2007

The increase in operating revenues in 2008 compared with 2007 in our other business operations is due to the following:

- Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, increased $16.6 million (20.3%) between the years due to an increase in volume of jobs performed.
- Revenues at E.W. Wylie Corporation (Wylie), our flatbed trucking company, increased $7.5 million (21.5%) mainly as a result of the impact of increased fuel costs on shipping rates. Miles driven by company-owned trucks increased 15.7% as a result of the addition of heavy haul and wind tower transport services. Miles driven by owner-operated trucks decreased 32.6%. Combined miles driven by company-owned and owner-operated trucks decreased 1.1% between the years, reflecting a reduction in transport activity related to the economic downturn that started in 2008.
- Revenues at Midwest Construction Services, Inc. (MCS), our electrical design and construction services company, decreased $10.3 million (15.0%) between the years as a result of a reduction in the number of jobs in progress in 2008 compared to 2007 in the area of electrical infrastructure for delivery of wind generated electricity and MCS supplied materials for more jobs in 2007 resulting in a reduction in material pass through costs and revenues in 2008.

The increase in cost of goods sold in 2008 compared with 2007 is due to the following:

- Foley's cost of goods sold increased $14.2 million, including increases of $6.2 million in direct labor and benefit costs, $5.1 million in subcontractor costs and $2.7 million in material costs as a result of increased construction activity and jobs in progress.
- Cost of goods sold at MCS decreased $14.7 million due to decreases in material and subcontractor costs directly related to MCS having fewer jobs in progress and supplying materials on fewer jobs in 2008. However, MCS's gross margins increased by $4.4 million mainly as a result of higher productivity and increased margins on wind turbine and electric transmission line projects in 2008.

The increase in operating expenses in 2008 compared with 2007 is due to the following:

- Wylie's operating expenses increased $8.8 million between the years. Fuel costs increased $6.9 million as a result of higher diesel fuel prices and a 15.7% increase in miles driven by company-owned trucks. Labor and benefit costs increased by $1.3 million and equipment rental costs increased by $0.6 million due to the addition of heavy-haul services in the fourth quarter of 2007.
- MCS's operating expenses increased $2.0 million between the years due to increases in salary, benefit and professional services expenses.
- Foley's operating expenses increased $0.9 million between the years due to increases in labor, professional services and insurance costs.
- Operating expenses at Otter Tail Energy Services Company, (OTESCO), our energy services subsidiary, increased $0.4 million between the years related to the investigation of renewable energy wind-generation projects.

2007 compared with 2006

The increase in operating revenues in 2007 compared with 2006 in our other business operations is due to the following:

- Revenues at MCS increased $22.9 million (49.9%) between the years as a result of an increase in volume of jobs in 2007.
- Revenues at Foley increased $17.3 million (26.9%) between the years due to an increase in the volume of jobs in progress.
- Revenues at Wylie were unchanged between the years.

The increase in cost of goods sold in 2007 compared with 2006 is due to the following:

- Cost of goods sold at MCS increased $25.0 million mainly due to increases in material, subcontractor, direct labor and insurance costs related to the increase in volume of jobs between the years. Lower than expected margins on certain construction projects at MCS was the main factor contributing to the decrease in operating income between the years.

- Cost of goods sold at Foley increased $16.6 million mainly due to increases in direct labor, employee benefits, and subcontractor and material costs as a result of the increased volume of work performed between the years.

The increase in operating expenses in 2007 compared with 2006 is due to the following:

- Operating expenses at MCS were unchanged between the years.
- Operating expenses at Foley increased $0.5 million between the years as a result of increased labor, benefit and insurance expenses. Also, Foley's 2006 expenses reflect the recovery of $0.2 million in bad debts.
- Operating expenses at Wylie were unchanged between the years.

The decrease in depreciation and amortization expense in 2007 compared with 2006 reflects the effects of a decision by Wylie to lease rather than buy replacement trucks for its fleet.

CORPORATE

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

(in thousands)	2008	% change	2007	% change	2006
Operating Expenses	$ 15,867	62	$ 9,824	(13)	$ 11,322
Depreciation and Amortization	538	(7)	579	(1)	587

2008 compared with 2007

Corporate operating expenses increased $6.0 million as a result of a combination of increases in self insured health insurance plan costs, insurance expenses and claims experience in the captive insurance company, stock-based compensation and benefit expenses and outside professional service costs related to the formation of a holding company. These increases were partially offset by a decrease in incentive compensation expense.

2007 compared with 2006

Corporate operating expenses decreased $1.5 million as a result of a combination of lower insurance costs at our captive insurance company and lower health insurance plan costs.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS

Other income and deductions increased by $2.1 million in 2008 compared with 2007 mainly as a result of an increase in Allowance for Funds used During Construction (AFUDC) at the electric utility in 2008. No equity AFUDC was recorded in 2007 because our 2007 average short-term debt balance was in excess of the average balance of Construction Work in Progress (CWIP) at the electric utility in 2007. Average CWIP exceeded average short-term debt in 2008. As a result, 63% of AFUDC in 2008 was equity funded.

Other income and deductions increased by $2.5 million in 2007 compared with 2006 mainly due to a noncash charge of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction at the electric utility.

CONSOLIDATED INTEREST CHARGES

Interest expense increased $6.1 million in 2008 compared with 2007 primarily as a result of a net increase of $87 million in long-term debt in August and October of 2007. Short-term debt interest expense increased by $1.8 million in 2008 as a result of a $76.3 million increase in the average daily balance of short-term debt outstanding in 2008, mitigated by a 1.9 percentage point decrease in the weighted average interest rate paid on short-term debt between the years. Interest expense also increased in 2008 as a result of a $0.5 million reduction in capitalized interest in 2008 compared with 2007.

Interest expense increased $1.4 million in 2007 compared with 2006 as a result of a net increase of $87 million in long-term debt in 2007. Short-term debt interest expense increased $1.8 million as a result of an increase in the average daily balance of short-term debt outstanding and higher interest rates in 2007 compared with 2006. Increases in interest expense on both long-term and short-term debt were partially offset by a $2.4 million increase in capitalized interest in 2007.

CONSOLIDATED INCOME TAXES

The $12.9 million (46.2%) reduction in income tax expense from continuing operations in 2008 compared with 2007 is mostly due to a 38.8% decrease in income from continuing operations before income taxes. The decrease also is due to federal production tax credits earned on electricity generated from renewable resources in 2008. These items caused our effective tax rate on income from continuing operations to be 30.0% in 2008 compared with 34.1% in 2007.

The $0.9 million (3.2%) increase in income tax expense from continuing operations in 2007 compared to 2006 is due, in part, to a 5.2% increase in income from continuing operations before income taxes. Our effective tax rate on income from continuing operations was 34.1% in 2007 compared with 34.8% in 2006.

DISCONTINUED OPERATIONS

In 2006, we sold the natural gas marketing operations of OTESCO. Discontinued operations includes the operating results of OTESCO's natural gas marketing operations and an after-tax gain on the sale of its natural gas marketing operations of $0.3 million in 2006.

IMPACT OF INFLATION

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

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

HOLDING COMPANY REORGANIZATION

Our Board of Directors has authorized a holding company reorganization of our 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 Federal Energy Regulatory Commission (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 North Dakota Public Service Commission (NDPSC) approved our application to form a holding company. In a meeting held on October 30, 2008, the South Dakota Public Utilities Commission (SDPUC) approved our application to form a new holding company. The Minnesota Public Utilities Commission (MPUC) approved our 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.

2009 BUSINESS OUTLOOK

We anticipate 2009 diluted earnings per share to be in the range of $1.10 to $1.50. This guidance considers the seasonality of the operating cycles of our businesses and reflects challenges presented by an ongoing economic recession and our plans to prudently manage operating expenses and capital expenditures across all our operating companies. Our current consolidated capital expenditures expectation for 2009 is in the range of $60 to $70 million. This compares with $266 million of capital expenditures in 2008. Some of our businesses could benefit from renewable energy development incentives included in the American Recovery and Reinvestment Act passed by Congress and signed by the President in February 2009. We continue to explore investments in wind projects for the electric segment that could have a positive effect on our earnings and returns on capital. There could be additional capital expenditure opportunities available as well for some of our nonelectric businesses as a result of the passage of the American Recovery and Reinvestment Act of 2009.

Contributing to our earnings guidance for 2009 are the following items:

- We expect increased levels of revenue and net income from our electric segment in 2009 as a result of recently granted rate increases and resource recovery riders. The expected increase in revenues includes Minnesota and North Dakota renewable resource cost recovery rider revenue related to the Ashtabula Wind Center that was placed in service in late 2008, an interim rate increase of approximately $4.8 million, or 4.1%, which is part of a rate case filed with the NDPSC in November 2008 requesting a general rate increase of approximately $6.1 million, or 5.1%. Interim rates remain in effect for all North Dakota customers until the NDPSC makes a final determination on the electric utility's request, which is expected to occur by August 1, 2009. Expectations in 2009 also reflect a request for an increase in revenues in South Dakota of approximately $3.8 million annually, or 15.3% ($1.3 million in 2009). A final decision on the request is expected from the SDPUC in mid-summer 2009 with no provision for an increase in rates in the interim.
- We expect our plastics segment's 2009 performance to be below 2008 earnings given continued poor economic conditions. Announced capacity expansions are not expected to be brought on line until the economy improves and demand for PVC pipe increases.
- We expect earnings from our manufacturing segment to improve in 2009. Business conditions at BTD remain relatively strong and earnings are expected to increase in 2009 given full year operating results of Miller Welding, acquired in May 2008, an expanded customer base and expected improvements in manufacturing processes. While the economy is expected to impact the amount of spending on waterfront products, earnings are expected to improve at ShoreMaster compared with 2008 given the restructuring that has occurred in its business. The Adelanto facility has been closed, workforce reductions have been put in place, capital spending is being limited and improved profitability is expected on commercial projects in 2009. At DMI, we expect a decline in earnings in 2009 due to wind developers' limited access to financing which has resulted in cancellation or suspension of orders across the industry. Industry forecasts for megawatt installations of wind power in 2009 portray a decrease of between 25 to 50 percent from 2008. T. O. Plastics' earnings are expected to remain flat between the years. Backlog in place in the manufacturing segment to support 2009 revenues is approximately $241 million compared with $295 million one year ago.
- We expect increased net income from our health services segment in 2009 as it focuses on improving its mix of imaging assets and asset utilization rates and has implemented cost reductions across the segment.
- We expect increased net income from our food ingredient processing business in 2009 based on expectations of higher sales volumes, strong pricing for products, lower energy costs and higher production levels in 2009 compared with 2008. This business has backlog in place for 2009 of 48 million pounds compared with 52 million pounds one year ago.
- We expect our other business operations segment to have a similar level of earnings in 2009 compared with 2008. Backlog in place for the construction businesses is $71 million for 2009 compared with $77 million one year ago.
- We expect corporate general and administrative costs to decrease in 2009.

Our outlook for 2009 is dependent on a variety of factors and is subject to the risks and uncertainties discussed under "Risk Factors and Cautionary Statements."

LIQUIDITY

The following table presents the status of our lines of credit as of December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2008	Restricted due to Outstanding Letters of Credit	Available on December 31, 2008
Varistar Credit Agreement	$ 200,000	$ 107,849	$ 14,445	$ 77,706
Electric Utility Credit Agreement	170,000	27,065	—	142,935
Total	$ 370,000	$ 134,914	$ 14,445	$ 220,641

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if current market conditions continue. Despite the difficult year in 2008, our balance sheet is strong and we are in compliance with our debt covenants. We completed an equity offering in September 2008, which allowed us to invest in major organic growth opportunities in wind energy projects.

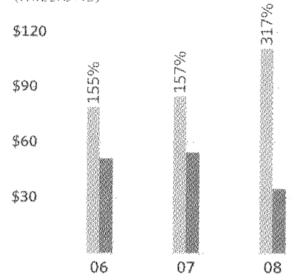
We believe our financial condition is strong and that our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of solid credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. Additional equity and debt financing will be required in the period 2009 through 2013 given our current capital expansion plans over this period. See "Capital Resources" section for further discussion. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

In March 2008, DMI entered into a three-year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation (GECC) on a revolving basis. Accounts receivable totaling $132.9 million were sold in 2008. Discounts, fees and commissions of $0.7 million for the year ended December 31, 2008 were charged to operating expenses in the consolidated statements of income. The balance of receivables sold that were still outstanding to the buyer as of December 31, 2008 was $25.3 million. The sales of these accounts receivable are reflected as a reduction of accounts receivable in the 2008 consolidated balance sheet and the proceeds are included in the cash flows from operating activities in the 2008 consolidated statement of cash flows.

In December 2007, ShoreMaster entered into an agreement with GE Commercial Distribution Finance Corporation (CDF) to provide floor plan financing for certain dealer purchases of ShoreMaster products. Financings under this agreement began in 2008. This agreement has improved our liquidity by financing dealer purchases of ShoreMaster's products without requiring substantial use of working capital. ShoreMaster is paid by CDF shortly after product shipment for purchases financed under this agreement. The floor plan financing agreement requires ShoreMaster to repurchase new and unused inventory repossessed by CDF to satisfy the dealer's obligations to CDF under this agreement. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF's security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $5.0 million on December 31, 2008. ShoreMaster has incurred no losses under this agreement. We believe current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement. CDF has notified ShoreMaster that it is exercising its right under this agreement to terminate the agreement effective February 28, 2009. The termination of the agreement will have no effect on ShoreMaster's obligations to CDF for any products financed, advances made or approvals granted by CDF under the agreement prior to the effective termination date. Additionally, ShoreMaster is liable for expenses incurred by CDF before or after the effective termination date in connection with the collection of any amounts or other charges as set forth in the agreement. As part of its marketing programs, ShoreMaster pays floor plan financing costs of its dealers for CDF financed purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer's order.

Cash provided by operating activities of continuing operations was $111.3 million in 2008 compared with $84.8 million in 2007. The $26.5 million increase in cash provided by operating activities of continuing operations mainly reflects a $24.6 million reduction in cash paid for income taxes in 2008. See note 1 to our 2008 consolidated financial statements. In addition, discretionary cash contributions to our funded pension plan were decreased by $2.0 million in 2008. Cash used for working capital items was $27.3 million in 2008 compared with $28.5 million in 2007, a decrease of $1.2 million between the years. Cash used for working capital in 2008 includes: (1) a net increase in interest payable and income taxes receivable of $25.2 million, mainly related to bonus tax depreciation, federal production tax credits and North Dakota wind energy tax credits earned in 2008, (2) an increase in other current assets of $12.4 million, mainly due to a $23.1 million increase in costs and estimated earnings in excess of billings at DMI offset by an $8.5 million reduction in accrued revenues at the electric utility, and (3) a decrease in payables and other current liabilities of $8.6 million, mainly due to a decrease in accounts payable at the plastic pipe companies as a result of reductions in PVC resin purchases, offset by (4) a decrease in receivables of $19.5 million mainly related to DMI's sales of receivables to GECC in 2008.

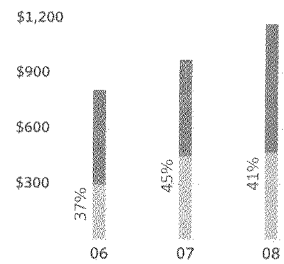
CASH REALIZATION RATIOS—CONTINUING OPERATIONS
(MILLIONS)



The cash realization ratio represents cash flows from continuing operations expressed as a percent of net income from continuing operations.

Cash flows from operations
Net income

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



Otter Tail has maintained a 37-45% interest-bearing debt to total capital ratio for the past three years.

Total capital
Interest-bearing debt
(includes short-term debt)

Net cash used in investing activities was $299.4 million in 2008 compared with $164.0 million in 2007. Cash used for capital expenditures increased by $103.9 million between the years. Cash used for capital expenditures at the electric utility increased by $94.5 million, mainly due to 2008 payments for assets constructed at the Langdon Wind Energy Center in late 2007 and payments for the construction of 32 wind turbines at the Ashtabula Wind Center in 2008. The electric utility also made major capital expenditures in 2008 to upgrade a transmission line in Cass County, North Dakota to serve increasing loads and improve service reliability in that region. Cash used for capital expenditures in our plastics segment increased $5.6 million, primarily related to the installation of a new PVC pipe extrusion line at the Hampton, Iowa plant. Cash used for capital expenditures at DMI increased $3.4 million between the years related to expansion of production capacity at its West Fargo and Tulsa plants. We paid $41.7 million in cash to acquire Miller Welding in May 2008. We completed two acquisitions in 2007 for a combined purchase price of $6.8 million.

Net cash provided by financing activities was $154.6 million in 2008 compared with $113.2 million in 2007. Proceeds from the issuance of common stock, net of issuance expenses, were $156.6 million in 2008 compared with $7.7 million in 2007. We issued 5,175,000 common shares in a public offering in September 2008. During 2008, 276,685 common shares were issued for stock options exercised compared with 298,601 common shares issued for stock options exercised in 2007. We received $1.2 million in proceeds from the issuance of long-term debt and repaid $3.6 million in long-term debt in 2008. In 2007, we received proceeds of $203.4 million in cash from the issuance of debt, net of debt issuance expenses, and paid $118.2 million to retire or refinance debt. Proceeds from short-term borrowings were $39.9 million in 2008 compared with $56.1 million in 2007. Proceeds from short-term borrowings were used to help fund construction expenditures in 2008. Dividends paid on common and preferred shares in 2008 increased $2.6 million in 2008 compared with 2007. The increase in dividend payments is due to a two cent per share increase in common dividends paid and an increase of 5,534,831 common shares outstanding between the years, most of which were issued for the September 2008 public offering and only received dividends in the fourth quarter of 2008.

CAPITAL REQUIREMENTS

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

Cash used for consolidated capital expenditures was $266 million in 2008, $162 million in 2007 and $69 million in 2006. As a result of the ongoing economic recession and difficult credit market conditions we have reduced capital expenditures across all of our operating companies. Estimated capital expenditures for 2009 are $61 million. Total capital expenditures for the five-year period 2009 through 2013 are estimated to be approximately $884 million, which includes $395 million for our 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 CapX 2020 projects. The breakdown of 2006, 2007 and 2008 actual and 2009 through 2013 estimated capital expenditures by segment is as follows:

(in millions)	2006	2007	2008	2009	2009–2013
Electric	$ 35	$ 104	$ 199	$ 35	$ 698
Plastics	5	3	9	5	18
Manufacturing	20	43	48	13	115
Health Services	5	5	4	3	27
Food Ingredient Processing	2	—	2	3	14
Other Business Operations	2	6	4	2	11
Corporate	—	1	—	—	1
Total	$ 69	$ 162	$ 266	$ 61	$ 884

The electric segment continues to review another wind project called the Luverne Wind Farm. The expected cost of this 49.5 megawatt project is $100 to $110 million. This project is subject to our ability to obtain acceptable financing terms and to approval by our Board of Directors. There could be additional capital expenditure opportunities available as well for some of our nonelectric businesses as a result of the passage of the American Recovery and Reinvestment Act of 2009. 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 electric utility's future generation requirements.

The following table summarizes our contractual obligations at December 31, 2008 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1–3 Years	3–5 Years	More than 5 Years
Long-Term Debt Obligations	**$ 343**	$ 4	$ 94	$ 10	$ 235
Interest on Long-Term Debt Obligations	**246**	21	40	28	157
Coal Contracts (required minimums)	**154**	54	60	18	22
Capacity and Energy Requirements	**140**	24	17	11	88
Operating Lease Obligations	**130**	46	57	17	10
Postretirement Benefit Obligations	**58**	3	7	8	40
Other Purchase Obligations	**42**	42	—	—	—
Total Contractual Cash Obligations	**$1,113**	$ 194	$ 275	$ 92	$ 552

Interest on $10.4 million of variable-rate debt outstanding on December 31, 2008 was projected based on the interest rates applicable to that debt instrument on December 31, 2008. Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan as we are not currently required to make a contribution to that plan.

CAPITAL RESOURCES

The following table presents the status of our lines of credit as of December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2008	Restricted due to Outstanding Letters of Credit	Available on December 31, 2008
Varistar Credit Agreement	$ 200,000	$ 107,849	$ 14,445	$ 77,706
Electric Utility Credit Agreement	170,000	27,065	—	142,935
Total	$ 370,000	$ 134,914	$ 14,445	$ 220,641

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, solid credit ratings, and alternative financing arrangements such as leasing. Equity or debt financing will be required in the period 2009 through 2013 given the expansion plans related to our electric segment to fund construction of new rate base investments, in the event we decide to reduce borrowings under our lines of credit, refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

On December 23, 2008 our wholly owned subsidiary, Varistar Corporation (Varistar), entered into a $200 million Amended and Restated Credit Agreement (the Varistar Credit Agreement) with the Banks named therein, U.S. Bank National Association, a national banking 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. The Varistar Credit Agreement amends and restates the $200 million Credit Agreement, dated as of October 2, 2007 (the Original Credit Agreement), among the parties to the Varistar Credit Agreement, and is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Original Credit Agreement was amended to provide that, in the event we elect to form a holding company, the Varistar Credit Agreement will become an obligation of the new holding company on the terms and subject to the conditions specified in the Varistar Credit Agreement, which include changes to the interest rate and financial covenants. The line of credit may be increased to $300 million on the terms and subject to the conditions described in the Varistar Credit Agreement and will expire on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 2.0%, subject to adjustment based on Varistar's adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). In the event we elect to form a holding company on the terms and subject to the conditions specified in the Varistar Credit Agreement (the Permitted Reorganization), the interest rate for loans after the effectiveness of the Permitted Reorganization will be based on the senior unsecured credit ratings of the new holding company.

The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Varistar Credit Agreement also contains affirmative covenants and events of default. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries.

On July 30, 2008 Otter Tail Corporation, dba Otter Tail Power Company replaced its credit agreement with U.S. Bank National Association, which provided for a $75 million line of credit, with a new credit agreement providing for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million as described in the new credit agreement. The new credit agreement (the Electric Utility Credit Agreement) is between Otter Tail Corporation, dba Otter Tail Power Company and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The Electric Utility Credit Agreement is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of our senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement also contains affirmative covenants and events of default. The Electric Utility Credit Agreement is subject to renewal on July 30, 2011.

The note purchase agreement relating to our $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement), the note purchase agreement relating to our $50 million 5.778% senior note due November 30, 2017 (the Cascade Note Purchase Agreement), and the note purchase agreement relating to our $155 million senior unsecured notes issued in four series consisting of $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the 2007 Note Purchase Agreement) each states that we may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require us to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states we must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement and the 2007 Note Purchase Agreement each contains a number of restrictions on us and our subsidiaries. In each case these include restrictions on our ability and the ability of certain of our subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. Our obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of our subsidiaries.

Financial Covenants

The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, the Lombard US Equipment Finance Note and the financial guaranty insurance policy with Ambac Assurance Corporation relating to our pollution control refunding bonds contain covenants by us to not permit our debt-to-total capitalization ratio to exceed 60% or permit our interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, our interest coverage ratio) to be less than 1.5 to 1. On effectiveness of the Permitted Reorganization, the Varistar Credit Agreement will contain similar covenants applicable to the new holding company. The note purchase agreements further restrict us from allowing our priority debt to exceed 20% of total capitalization. The Varistar Credit Agreement also contains certain financial covenants that will apply to Varistar until the effectiveness of the Permitted Reorganization. Specifically, Varistar must maintain a fixed charge coverage ratio (as defined in the Varistar Credit Agreement) of not less than 1.20 to 1.00 for each period of four consecutive fiscal quarters through March 31, 2009, and not less than 1.25 to 1.00 for each period of four consecutive fiscal quarters ending June 30, 2009 and thereafter. In addition, Varistar must not permit its Cash Flow Leverage Ratio (as defined in the Varistar Credit Agreement) to exceed 3.25 to 1.00 for each period of four consecutive fiscal quarters through March 31, 2009, or to exceed 3.00 to 1.00 for each period of four consecutive fiscal quarters ending June 30, 2009 and thereafter. Our Credit and Note Purchase Agreements do not contain any provisions that would trigger an acceleration of our debt caused by credit rating levels assigned to us by rating agencies. We and Varistar were in compliance with all of the financial covenants under our respective financing agreements as of December 31, 2008.

Our securities ratings at December 31, 2008 were:

	Moody's Investors Service	Standard & Poor's
Senior Unsecured Debt	A3	BBB-
Preferred Stock	Not rated	BB
Outlook	Negative	Stable

On September 26, 2008 Standard and Poor's Ratings Services lowered its corporate credit rating and senior unsecured debt rating on our company from BBB+ to BBB- and lowered its rating on our preferred stock from BBB- to BB and changed its outlook from negative to stable, citing a growing appetite for nonutility businesses in combination with expected credit measures that are more consistent with the BBB- rating and expected cash flow constraints given current economic indicators.

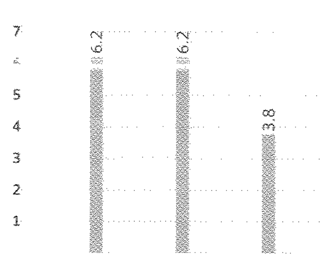
On January 14, 2009 Moody's Investors Service placed the ratings of our senior unsecured debt under review for possible downgrade. The review for possible downgrade follows the January 7, 2009 order of the MPUC approving, with conditions, the restructuring of Otter Tail Corporation to establish a separate subsidiary corporation to conduct its utility operations.

Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. Downgrades in these securities ratings could adversely affect our company. Further, downgrades could increase our borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on our debt obligations.

Our ratio of earnings to fixed charges from continuing operations, which includes imputed finance costs on operating leases, was 2.4x for 2008 compared to 3.5x for 2007 and our long-term debt interest coverage ratio before taxes was 3.8x for 2008 compared to 6.2x for 2007. During 2009, we expect these coverage ratios to increase, assuming 2009 net income meets our expectations.

LONG-TERM DEBT INTEREST COVERAGE

(times interest earned before tax)



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

OFF-BALANCE-SHEET ARRANGEMENTS

We do not have any off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

RISK FACTORS AND CAUTIONARY STATEMENTS

We are including the following factors and cautionary statements in this Annual Report to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by us or on our behalf. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All these forward-looking statements, whether written or oral and whether made by us or on our behalf, are also expressly qualified by these factors and cautionary statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of the factors, nor can we assess the effect of each factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The following factors and the other matters discussed herein are important factors that could cause actual results or outcomes for our company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

GENERAL

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

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

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

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

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

As of December 31, 2008, our defined benefit pension plan assets had declined significantly since December 31, 2007. We are 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, we could be required to contribute additional capital to the pension plan.

Any significant impairment of our goodwill would cause a decrease in our assets and a reduction in our net operating performance.
We had approximately $106.8 million of goodwill recorded on our consolidated balance sheet as of December 31, 2008. We have recorded goodwill for businesses in each of our business segments, except for our electric utility. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net operating performance. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge.

We currently have $24.3 million of goodwill and a $3.3 million nonamortizable trade name recorded on our balance sheet related to the acquisition of Idaho Pacific Holdings, Inc. (IPH) in 2004. If conditions of low sales prices, high energy and raw material costs and a shortage of raw potato supplies return, as experienced in 2006, or operating margins do not improve according to our projections, the reductions in anticipated cash flows from this business may indicate that its fair value is less than its book value resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with IPH and a corresponding charge against earnings.

We currently have $12.3 million of goodwill and $4.9 million in nonamortizable trade names recorded on our balance sheet related to the acquisition of ShoreMaster and its subsidiary companies. If current economic conditions continue to impact the amount of sales of waterfront products and ShoreMaster is not successful with reorganizing and streamlining its business to improve operating margins according to our projections, the reductions in anticipated cash flows from this business may indicate that its fair value is less than its book value resulting in an impairment of some or all of the goodwill and nonamortizable intangible assets associated with ShoreMaster and a corresponding charge against earnings.

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

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

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

Our plans to grow and diversify through acquisitions may not be successful, which could result in poor financial performance.
As part of our business strategy, we intend to acquire new businesses. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. If we are unable to make acquisitions, we may be unable to realize the growth we anticipate. Future acquisitions could involve numerous risks including: difficulties in integrating the operations, services, products and personnel of the acquired business; and the potential loss of key employees, customers and suppliers of the acquired business. If we are unable to successfully manage these risks of an acquisition, we could face reductions in net income in future periods.

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

The terms of some of our contracts could expose us to unforeseen costs and costs not within our control, which may not be recoverable and could adversely affect our results of operations and financial condition.
DMI and ShoreMaster, two businesses in our manufacturing segment, and our construction companies frequently provide products and services pursuant to fixed-price contracts. Revenues recognized on jobs in progress under fixed-price contracts for the year ended December 31, 2008 were $425 million. Under those contracts, we agree to perform the contract for a fixed price and, as a result, can improve our expected profit by superior contract performance, productivity, worker safety and other factors resulting in cost savings. However, we could incur cost overruns above the approved contract price, which may not be recoverable.

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

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

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

ELECTRIC

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

As of December 31, 2008 the electric utility had capitalized $11.6 million in costs related to the planned construction of a second electric generating unit at the electric utility's Big Stone Plant site. 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. Additionally, if the electric utility is unable to complete the construction of Big Stone II and commence operations, it may be forced to purchase power in order to meet customer needs. There is no guarantee that in such a case the electric utility would be able to obtain sufficient supplies of power at reasonable costs. If it is forced to pay higher than normal prices for power, the increase in costs could reduce our earnings if the electric utility is not able to recover the increased costs from its electric customers through the FCA.

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

Future operating results of our 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 retail 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 electric utility's request, which is expected by August 1, 2009. If final rates are lower than interim rates, the electric utility will refund North Dakota customers the difference with interest.

We may not be able to respond effectively to deregulation initiatives in the electric industry, which could result in reduced revenues and earnings.
We may not be able to respond in a timely or effective manner to the changes in the electric industry that may occur as a result of regulatory initiatives to increase wholesale competition. These regulatory initiatives may include further deregulation of the electric utility industry in wholesale markets. Although we do not expect retail competition to come to the states of Minnesota, North Dakota and South Dakota in the foreseeable future, we expect competitive forces in the electric supply segment of the electric business to continue to increase, which could reduce our revenues and earnings.

Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.
Operation of electric generating facilities involves risks which can adversely affect energy output and efficiency levels. Most of our generating capacity is coal-fired. We rely on a limited number of suppliers of coal, making us vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. We are a captive rail shipper of the BNSF Railway for shipments of coal to our Big Stone and Hoot Lake plants, making us vulnerable to increased prices for coal transportation from a sole supplier. Higher fuel prices result in higher electric rates for our retail customers through fuel clause adjustments and could make us less competitive in wholesale electric markets. Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error and catastrophic events such as fires, explosions, floods, intentional acts of destruction or other similar occurrences affecting our electric generating facilities. The loss of a major generating facility would require us to find other sources of supply, if available, and expose us to higher purchased power costs.

Changes to regulation of generating plant emissions, including but not limited to carbon dioxide (CO_2) emissions, could affect our operating costs and the costs of supplying electricity to our customers.
Existing or new laws or regulations passed or issued by federal or state authorities addressing climate change or reductions of greenhouse gas emissions, such as mandated levels of renewable generation, mandatory reductions in CO_2 emission levels, taxes on CO_2 emissions or cap and trade regimes, that result in increases in electric service costs could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the electric utility provides service or through increased market prices for electricity.

PLASTICS

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.
We rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors accounted for approximately 94% of our total purchases of PVC resin in 2008 and approximately 95% of our total purchases of PVC resin in 2007. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which may increase the risk of a shortage of resin in the event of a hurricane or other natural disaster in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources are available.

We compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.
The plastic pipe industry is highly fragmented and competitive due to the large number of producers and the fungible nature of the product. We compete not only against other PVC pipe manufacturers, but also against ductile iron, steel, concrete and clay pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope, and the principal areas of competition are a combination of price, service, warranty and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics business.

Reductions in PVC resin prices can negatively affect our plastics business.
The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower. Reductions in PVC resin prices could negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

MANUFACTURING

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

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

Each of our manufacturing companies has significant customers and concentrated sales to such customers. If our relationships with significant customers should change materially, it would be difficult to immediately and profitably replace lost sales. Fluctuations in foreign currency exchange rates could have a negative impact on the net income and competitive position of our wind tower manufacturing operations in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

HEALTH SERVICES

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

Our health services businesses derive significant revenue from direct billings to customers and third-party payors such as Medicare, Medicaid, managed care and private health insurance companies for our diagnostic imaging services. Moreover, customers who use our diagnostic imaging services generally rely on reimbursement from third-party payors. Adverse changes in the rates or methods of third-party reimbursements could reduce the number of procedures for which we or our customers can obtain reimbursement or the amounts reimbursed to us or our customers.

Our health services businesses may be unable to continue to maintain agreements with Philips Medical from which we derive significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.

Our health services business agreement with Philips Medical expires on December 31, 2013. This agreement can be terminated on 180 days written notice by either party for any reason. It also includes other compliance requirements. If this agreement is terminated under the existing termination provisions or we were not able to comply with the agreement, the financial results of our health services operations would be adversely affected.

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

Although we believe substantially all of our diagnostic imaging systems can be upgraded to maintain their state-of-the-art character, the development of new technologies or refinements of existing technologies might make our existing systems technologically or economically obsolete, or cause a reduction in the value of, or reduce the need for, our systems.

Actions by regulators of our health services operations could result in monetary penalties or restrictions in our health services operations.

Our health services operations are subject to federal and state regulations relating to licensure, conduct of operations, ownership of facilities, addition of facilities and services and payment of services. Our failure to comply with these regulations, including new regulations released October 30, 2008 by the Center for Medicare & Medical Services, or our inability to obtain and maintain necessary regulatory approvals, may result in adverse actions by regulators with respect to our health services operations, which may include civil and criminal penalties, damages, fines, injunctions, operating restrictions or suspension of operations. Any such action could adversely affect our financial results. Courts and regulatory authorities have not fully interpreted a significant number of these laws and regulations, and this uncertainty in interpretation increases the risk that we may be found to be in violation. Any action brought against us for violation of these laws or regulations, even if successfully defended, may result in significant legal expenses and divert management's attention from the operation of our businesses.

FOOD INGREDIENT PROCESSING

Our company that processes dehydrated potato flakes, flour and granules, IPH, competes in a highly competitive market and is dependent on adequate sources of potatoes for processing.

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

The principal raw material used by our potato processing company is washed process-grade potatoes from growers. These potatoes are unsuitable for use in other markets due to imperfections. They are not subject to the United States Department of Agriculture's general requirements and expectations for size, shape or color. While our food ingredient processing company has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers and other factors. A loss or shortage of raw materials or the necessity of paying much higher prices for raw materials or fuel could adversely affect the financial performance of this company. Fluctuations in foreign currency exchange rates could have a negative impact on our potato processing company's net income and competitive position because approximately 25% of IPH sales in 2008 were outside the United States and the Canadian plant pays its operating expenses in Canadian dollars.

OTHER BUSINESS OPERATIONS

Our construction companies may be unable to properly bid and perform on projects.

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2008 we had exposure to market risk associated with interest rates because we had $107.8 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 2.0% under the Varistar Credit Agreement and $27.1 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under the Electric Utility Credit Agreement. At December 31, 2008 we had exposure to changes in foreign currency exchange rates. DMI has market risk related to changes in foreign currency exchange rates at its plant in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 25% of IPH sales in 2008 were outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars. However, IPH's Canadian subsidiary has locked in exchange rates for the exchange of U.S. dollars (USD) for Canadian dollars (CAD) for approximately 100% of its cash needs for the period January 1, 2009 through July 31, 2009 and approximately 50% of its cash needs for the period August 1, 2009 through October 31, 2009 by entering into forward foreign currency exchange contracts. On December 31, 2008 IPH's Canadian subsidiary held contracts for the exchange of $6.8 million USD for $7.9 million CAD.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of December 31, 2008 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2008, annualized interest expense and pre-tax earnings would change by approximately $104,000.

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

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

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

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2008 the electric utility had recognized, on a pretax basis, $123,000 in net unrealized losses on open forward contracts for the purchase and sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of December 31, 2008, 100% are offset by forward energy purchase contracts in terms of volumes and delivery periods.

We have in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. With the advent of the MISO Day 2 market in April 2005, we made several changes to our energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, we implemented a Value at Risk (VaR) limit to further manage market price risk. Exposure to price risk on any open positions as of December 31, 2008 was not material.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on our consolidated balance sheet as of December 31, 2008 and the change in our consolidated balance sheet position from December 31, 2007 to December 31, 2008:

(in thousands)	**December 31, 2008**
Current Asset—Marked-to-Market Gain	$ 405
Regulatory Asset—Deferred Marked-to-Market Loss	1,162
Total Assets	1,567
Current Liability—Marked-to-Market Loss	(1,690)
Regulatory Liability—Deferred Marked-to-Market Gain	—
Total Liabilities	(1,690)
Net Fair Value of Marked-to-Market Energy Contracts	$ (123)

(in thousands)	**Year Ended December 31, 2008**
Fair Value at Beginning of Year	$ 632
Amount Realized on Contracts Entered into in 2007 and Settled in 2008	(1,169)
Changes in Fair Value of Contracts Entered into in 2007	537
Net Fair Value of Contracts Entered into in 2007 at Year End 2008	—
Changes in Fair Value of Contracts Entered into in 2008	(123)
Net Fair Value at End of Year	$ (123)

The $123,000 in recognized but unrealized net losses on the forward energy purchases and sales marked to market on December 31, 2008 is expected to be realized on physical settlement as scheduled in January and February of 2009.

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty's financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2008 was $252,000. As of December 31, 2008 we had a net credit risk exposure of $921,000 from 12 counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. We had no exposure at December 31, 2008 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The $921,000 credit risk exposure includes net amounts due to the electric utility on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2008. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able to increase prices for its finished products to recover increases in fuel costs.

In order to limit its exposure to fluctuations in future prices of natural gas, IPH entered into contracts with its natural gas suppliers in August 2008 for the firm purchase of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009 at fixed prices. These contracts qualify for the normal purchase exception to mark-to-market accounting under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivatives and Hedging Instruments*, as amended and interpreted.

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. The total amounts of contracts settled in 2008 and outstanding on December 31, 2008 along with net exchange losses realized in 2008 and recognized as of December 31, 2008 are presented in the following table:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in March 2008	April 2008–December 2008	$ 3,600	$ 3,695
Net Mark-to-Market Losses Realized on Settlement	April 2008–December 2008	(224)	
Contracts entered into in July 2008	August 2008–July 2009	$ 4,800	$ 5,003
Net Mark-to-Market Losses Realized on Settlement	August 2008–December 2008	(203)	
Mark-to-Market Losses on Open Contracts at Year End 2008	January 2009–July 2009	(401)	
Contracts entered into in October 2008	January 2009–October 2009	$ 4,000	$ 5,001
Mark-to-Market Gains on Open Contracts at Year End 2008	January 2009–October 2009	112	
Net Mark-to-Market Losses Realized on Settlement in 2008		$ (427)	
Net Mark-to-Market Losses Recognized on Open Contracts at Year End 2008		(289)	
Net Mark-to-Market Losses Recognized in 2008		$ (716)	

These contracts are derivatives subject to mark-to-market accounting. IPH does not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates with the intent of settling these contracts during their stated settlement periods and using the proceeds to pay its Canadian liabilities when they come due. These contracts do not qualify for hedge accounting treatment because the timing of their settlements did not and will not coincide with the payment of specific bills or existing contractual obligations. The foreign currency exchange forward contracts outstanding as of December 31, 2008 were valued and marked to market on December 31, 2008 based on quoted exchange values of similar contracts that could be purchased on December 31, 2008.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

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

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

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

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

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

The pension benefit cost for 2009 for our noncontributory funded pension plan is expected to be $3.4 million compared to $2.9 million in 2008. The estimated discount rate used to determine annual benefit cost accruals will be 6.70% in 2009; the discount rate used in 2008 was 6.25%. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of "Aa" published by recognized rating agencies, along with bond matching models specific to our plans as a basis to determine the rate.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2008, all other factors being held constant:

a 0.25 increase in the discount rate would have decreased our 2008 pension benefit cost by $350,000; a 0.25 decrease in the discount rate would have increased our 2008 pension benefit cost by $610,000; a 0.25 increase (or decrease) in the assumed rate of increase in future compensation levels would have increased (or decreased) our 2008 pension benefit cost by $500,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2008 pension benefit cost by $410,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase in the discount rate would have decreased our 2008 postretirement medical benefit costs by $60,000. A 0.25 decrease in the discount rate would have increased our 2008 postretirement medical benefit costs by $160,000. See note 12 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

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

REVENUE RECOGNITION

Our construction companies and two of our manufacturing companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at our wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. The duration of the majority of these contracts is less than a year. Revenues recognized on jobs in progress as of December 31, 2008 were $425 million. Any expected losses on jobs in progress at year-end 2008 have been recognized. We believe the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

Our electric utility's forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under generally accepted accounting principles. The market prices used to value the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service, and, as such, are estimates. Of the forward energy sales contracts that are marked to market as of December 31, 2008, 100% are offset by forward energy purchase contracts in terms of volumes and delivery periods. All of the forward energy contracts for the purchase and sale of electricity marked to market as of December 31, 2008 are scheduled for settlement prior to March 1, 2009.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

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

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

During 2008, $2.0 million of bad debt expense (0.16% of total 2008 revenue of $1.3 billion) was recorded and the allowance for doubtful accounts was $2.7 million (2.0% of trade accounts receivable) as of December 31, 2008. General economic conditions and specific geographic concerns are major factors that may affect the adequacy of the allowance and may result in a change in the annual bad debt expense. An increase or decrease in our consolidated allowance for doubtful accounts based on one percentage point of outstanding trade receivables at December 31, 2008 would result in a $1.4 million increase or decrease in bad debt expense.

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

DEPRECIATION EXPENSE AND DEPRECIABLE LIVES

The provisions for depreciation of electric utility property for financial reporting purposes are made on the straight-line method based on the estimated service lives (5 to 65 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.81% in 2008, 2.78% in 2007 and 2.82% in 2006. Depreciation rates on electric utility property are subject to annual regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

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

TAXATION

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2008 reflects the most likely probable expected outcome of these tax matters in accordance with FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, and SFAS No. 109, *Accounting for Income Taxes*, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

Deferred income taxes are provided for revenue and expenses which are recognized in different periods for income tax and financial reporting purposes. We assess our deferred tax assets for recoverability based on both historical and anticipated earnings levels. We have not recorded a valuation allowance related to the probability of recovery of our deferred tax assets as we believe reductions in tax payments related to these assets will be fully realized in the future.

ASSET IMPAIRMENT

We are required to test for asset impairment relating to property and equipment whenever events or changes in circumstances indicate that the carrying value of an asset might not be recoverable. We apply SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, in order to determine whether or not an asset is impaired. This standard requires an impairment analysis when indicators of impairment are present. If such indicators are present, the standard requires that if the sum of the future expected cash flows from a company's asset, undiscounted and without interest charges, is less than the carrying value, an asset impairment must be recognized in the financial statements. The amount of the impairment is the difference between the fair value of the asset and the carrying value of the asset.

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

As of December 31, 2008 an assessment of the carrying values of our long-lived assets and other intangibles indicated these assets were not impaired.

GOODWILL IMPAIRMENT

Goodwill is required to be evaluated annually for impairment, according to SFAS No. 142, *Goodwill and Other Intangible Assets*. The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. Step one is to test for potential impairment and requires that the fair value of the reporting unit be compared to its book value including goodwill. If the fair value is higher than the book value, no impairment is recognized. If the fair value is lower than the book value, a second step must be performed. The second step is to measure the amount of impairment loss, if any, and requires that a hypothetical purchase price allocation be done to determine the implied fair value of goodwill. This fair value is then compared to the carrying value of goodwill. If the implied fair value is lower than the carrying value, an impairment must be recorded.

We believe accounting estimates related to goodwill impairment are critical because the underlying assumptions used for the discounted cash flow can change from period to period and could potentially cause a material impact to the income statement. Management's assumptions about inflation rates and other internal and external economic conditions, such as earnings growth rate, require significant judgment based on fluctuating rates and expected revenues. Additionally, SFAS No. 142 requires goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. As of December 31, 2008 an assessment of the carrying values of our goodwill indicated no impairment.

PURCHASE ACCOUNTING

Through December 31, 2008, under SFAS No. 141, *Business Combinations*, we have accounted for our acquisitions under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The excess of purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The recorded values of assets and liabilities are based on third party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and, accordingly, our consolidated financial position or results of operations may be affected by changes in estimates and judgments.

Acquired assets and liabilities assumed that are subject to critical estimates include property, plant and equipment and intangible assets.

The fair value of property, plant and equipment is based on valuations performed by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

Intangible assets are identified and valued using the guidelines of SFAS No. 141. The fair value of intangible assets is based on estimates including royalty rates, customer attrition rates and estimated cash flows.

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

Beginning in 2009, we will account for acquisitions under the requirements of SFAS No. 141 (revised 2007), *Business Combinations*, issued in December 2007. SFAS No. 141(R) replaces the term "purchase method of accounting" with "acquisition method of accounting" and requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values.

KEY ACCOUNTING PRONOUNCEMENTS

SFAS No. 157, *Fair Value Measurements*, was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. The adoption of SFAS No. 157 on January 1, 2008 resulted in additional footnote disclosures related to the use of fair value measurements in the areas of investments, derivatives, asset retirement obligations, goodwill and asset impairment evaluations, financial instruments and acquisitions, but did not have a significant impact on our consolidated balance sheet, income statement or statement of cash flows.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115*, was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 159 on January 1, 2008. The adoption of this pronouncement had no effect on our consolidated financial statements because we had not opted, nor do we currently plan to opt, to apply fair value accounting to any financial instruments or other items that we are not currently required to account for at fair value.

SFAS No. 141(R), *Business Combinations*, was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*, and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*, was issued by the FASB in March 2008. SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities to improve the transparency of financial reporting. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Adoption of SFAS No. 161 will result in additional footnote disclosures related to our use of derivative instruments but those additional disclosures will not be extensive because the derivative instruments currently held by us are not designated as hedging instruments under SFAS No. 161.

MANAGEMENT'S REPORT REGARDING INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this annual report. The consolidated financial statements of Otter Tail Corporation (the Company) have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

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

Management has completed its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework* to conduct the required assessment of the effectiveness of the Company's internal control over financial reporting.

There have not been any changes in the Company's internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) during the fiscal year to which this report relates that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Based on this assessment, we believe that, as of December 31, 2008 the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, audited the Company's consolidated financial statements included in this annual report and issued an attestation report on the Company's internal control over financial reporting.

John Erickson, President and Chief Executive Officer

Kevin Moug

Kevin Moug, Chief Financial Officer
February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE SHAREHOLDERS OF OTTER TAIL CORPORATION

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and its subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, common shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company's internal control over financial reporting as of December 31, 2008 based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte + Touche LLP

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 25, 2009

CONSOLIDATED STATEMENTS OF INCOME—FOR THE YEARS ENDED DECEMBER 31

(in thousands, except per-share amounts)	**2008**	2007	2006
Operating Revenues			
Electric	**$ 339,726**	$ 323,158	$ 305,703
Nonelectric	**971,471**	915,729	799,251
Total Operating Revenues	**1,311,197**	1,238,887	1,104,954
Operating Expenses			
Production Fuel—Electric	**71,930**	60,482	58,729
Purchased Power—Electric System Use	**56,329**	74,690	58,281
Electric Operation and Maintenance Expenses	**115,300**	107,041	103,548
Cost of Goods Sold—Nonelectric (excludes depreciation; included below)	**775,292**	712,547	611,737
Other Nonelectric Expenses	**143,050**	121,110	115,290
Plant Closure Costs	**2,295**	—	—
Depreciation and Amortization	**65,060**	52,830	49,983
Property Taxes—Electric	**8,949**	9,413	9,589
Total Operating Expenses	**1,238,205**	1,138,113	1,007,157
Operating Income	**72,992**	100,774	97,797
Other Income and Deductions	**4,128**	2,012	(440)
Interest Charges	**26,958**	20,857	19,501
Income from Continuing Operations Before Income Taxes	**50,162**	81,929	77,856
Income Taxes—Continuing Operations	**15,037**	27,968	27,106
Net Income from Continuing Operations	**35,125**	53,961	50,750
Discontinued Operations			
Income from Discontinued Operations Net of Taxes of $28 in 2006	**—**	—	26
Gain on Disposition of Discontinued Operations Net of Taxes of $224 in 2006	**—**	—	336
Net Income from Discontinued Operations	**—**	—	362
Net Income	**35,125**	53,961	51,112
Preferred Dividend Requirements	**736**	736	736
Earnings Available for Common Shares	**$ 34,389**	$ 53,225	$ 50,376
Average Number of Common Shares Outstanding—Basic	**31,409**	29,681	29,394
Average Number of Common Shares Outstanding—Diluted	**31,673**	29,970	29,664
Basic Earnings Per Share:			
Continuing Operations (net of preferred dividend requirements)	**$ 1.09**	$ 1.79	$ 1.70
Discontinued Operations	**—**	—	0.01
	$ 1.09	$ 1.79	$ 1.71
Diluted Earnings Per Share:			
Continuing Operations (net of preferred dividend requirements)	**$ 1.09**	$ 1.78	$ 1.69
Discontinued Operations	**—**	—	0.01
	$ 1.09	$ 1.78	$ 1.70
Dividends Per Common Share	**$ 1.19**	$ 1.17	$ 1.15

See accompanying notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEETS, DECEMBER 31

(in thousands)	2008	2007
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 7,565	$ 39,824
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $2,744 for 2008 and $3,811 for 2007)	136,609	151,446
Other	13,587	14,934
Inventories	101,955	97,214
Deferred Income Taxes	8,386	7,200
Accrued Utility and Cost-of-Energy Revenues	24,030	32,501
Costs and Estimated Earnings in Excess of Billings	65,606	42,234
Income Taxes Receivable	26,754	283
Other	8,519	15,016
Total Current Assets	393,011	400,652
Investments	7,542	10,057
Other Assets	22,615	24,500
Goodwill	106,778	99,242
Other Intangibles—Net	35,441	20,456
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	7,247	6,986
Regulatory Assets and Other Deferred Debits	82,384	38,837
Total Deferred Debits	89,631	45,823
Plant		
Electric Plant in Service	1,205,647	1,028,917
Nonelectric Operations	321,032	257,590
Total	1,526,679	1,286,507
Less Accumulated Depreciation and Amortization	548,070	506,744
Plant—Net of Accumulated Depreciation and Amortization	978,609	779,763
Construction Work in Progress	58,960	74,261
Net Plant	1,037,569	854,024
Total	$ 1,692,587	$ 1,454,754

See accompanying notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEETS, DECEMBER 31

(in thousands, except share data)	2008	2007
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$ 134,914	$ 95,000
Current Maturities of Long-Term Debt	3,747	3,004
Accounts Payable	113,422	141,390
Accrued Salaries and Wages	29,688	29,283
Accrued Taxes	10,939	11,409
Other Accrued Liabilities	12,034	13,873
Total Current Liabilities	304,744	293,959
Pensions Benefit Liability	80,912	39,429
Other Postretirement Benefits Liability	32,621	30,488
Other Noncurrent Liabilities	19,391	23,228
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	123,086	105,813
Deferred Tax Credits	34,288	16,761
Regulatory Liabilities	64,684	62,705
Other	397	275
Total Deferred Credits	222,455	185,554
Capitalization (page 44)		
Long-Term Debt, Net of Current Maturities	339,726	342,694
Class B Stock Options of Subsidiary	1,220	1,255
Cumulative Preferred Shares	15,500	15,500
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2008—35,384,620 Shares; 2007—29,849,789 Shares	176,923	149,249
Premium on Common Shares	241,731	108,885
Retained Earnings	260,364	263,332
Accumulated Other Comprehensive (Loss) Income	(3,000)	1,181
Total Common Equity	676,018	522,647
Total Capitalization	1,032,464	882,096
Total	$ 1,692,587	$ 1,454,754

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(in thousands, except common shares outstanding)	Common Shares Outstanding	Par Value, Common Shares	Premium on Common Shares	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income/(Loss)	Total Equity
Balance, December 31, 2005	**29,401,223**	**$ 147,006**	**$ 96,768**	**$ (1,720)**	**$ 228,515**	**$ (6,139)**	**$ 464,430**
Common Stock Issuances, Net of Expenses	136,917	685	1,837				2,522
Common Stock Retirements	(16,370)	(82)	(378)				(460)
SFAS No. 123(R) Reclassifications (note 7)			(2,490)	1,720			(770)
Comprehensive Income:							
Net Income					51,112		51,112
Unrealized Gain on Marketable Equity Securities (net-of-tax)						56	56
Foreign Currency Exchange Translation (net-of-tax)						6	6
SFAS No. 87 Minimum Pension Liability Adjustment (net-of-tax)						4,257	4,257
Total Comprehensive Income							55,431
SFAS No. 158 Items (net-of-tax)							
Reversal of 12/31/06 Minimum Pension Liability Balance						3,296	3,296
Unrecognized Postretirement Benefit Costs						(24,585)	(24,585)
Unrecognized Costs Classified as Regulatory Assets						22,042	22,042
Tax Benefit for Exercise of Stock Options			288				288
Stock Incentive Plan Performance Award Accrual			2,404				2,404
Vesting of Restricted Stock Granted to Employees			1,096				1,096
Premium on Purchase of Stock for Employee Purchase Plan			(302)				(302)
Cumulative Preferred Dividends					(736)		(736)
Common Dividends					(33,886)		(33,886)
Balance, December 31, 2006	**29,521,770**	**$ 147,609**	**$ 99,223**	**$ —**	**$ 245,005**	**$ (1,067)(a)**	**$ 490,770**
Common Stock Issuances, Net of Expenses	336,508	1,683	6,018				7,701
Common Stock Retirements	(8,489)	(43)	(252)				(295)
Comprehensive Income:							
Net Income					53,961		53,961
Unrealized Gain on Marketable Equity Securities (net-of-tax)						4	4
Foreign Currency Exchange Translation (net-of-tax)						2,019	2,019
SFAS No. 158 Items (net-of-tax):							
Amortization of Unrecognized Postretirement Benefit Costs						165	165
Actuarial Gains and Regulatory Allocations Adjustments						60	60
Total Comprehensive Income							56,209
Tax Benefit for Exercise of Stock Options			1,092				1,092
Stock Incentive Plan Performance Award Accrual			2,213				2,213
Vesting of Restricted Stock Granted to Employees			860				860
Premium on Purchase of Stock for Employee Purchase Plan			(269)				(269)
Cumulative Effect of Adoption of FIN No. 48					(118)		(118)
Cumulative Preferred Dividends					(736)		(736)
Common Dividends					(34,780)		(34,780)
Balance, December 31, 2007	**29,849,789**	**$ 149,249**	**$ 108,885**	**$ —**	**$ 263,332**	**$ 1,181(a)**	**$ 522,647**
Common Stock Issuances, Net of Expenses	5,557,531	27,788	128,818				156,606
Common Stock Retirements	(22,700)	(114)	(642)				(756)
Comprehensive Income:							
Net Income					35,125		35,125
Unrealized Gain on Marketable Equity Securities (net-of-tax)						(40)	(40)
Foreign Currency Exchange Translation (net-of-tax)						(2,784)	(2,784)
SFAS No. 158 Items (net-of-tax):							
Amortization of Unrecognized Postretirement Benefit Costs						153	153
Actuarial Gains and Regulatory Allocations Adjustments						(1,510)	(1,510)
Total Comprehensive Income							30,944
Tax Benefit for Exercise of Stock Options			1,777				1,777
Stock Incentive Plan Performance Award Accrual			3,093				3,093
Vesting of Restricted Stock Granted to Employees			165				165
Premium on Purchase of Stock for Employee Purchase Plan			(365)				(365)
Cumulative Preferred Dividends					(736)		(736)
Common Dividends					(37,357)		(37,357)
Balance, December 31, 2008	**35,384,620**	**$ 176,923**	**$ 241,731**	**$ —**	**$ 260,364**	**$ (3,000)(a)**	**$ 676,018**

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

		Before Tax	Tax Effect	Net-of-Tax
	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (4,238)	$ 1,695	$ (2,543)
2006	Foreign Currency Exchange Translation	2,430	(972)	1,458
	Unrealized Gain on Marketable Equity Securities	30	(12)	18
	Net Accumulated Other Comprehensive Loss	$ (1,778)	$ 711	$ (1,067)
	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (3,863)	$ 1,545	$ (2,318)
2007	Foreign Currency Exchange Translation	5,795	(2,318)	3,477
	Unrealized Gain on Marketable Equity Securities	36	(14)	22
	Net Accumulated Other Comprehensive Income	$ 1,968	$ (787)	$ 1,181
	Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (6,125)	$ 2,450	$ (3,675)
2008	Foreign Currency Exchange Translation	1,155	(462)	693
	Unrealized Gain on Marketable Equity Securities	(30)	12	(18)
	Net Accumulated Other Comprehensive Loss	$ (5,000)	$ 2,000	$ (3,000)

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS—FOR THE YEARS ENDED DECEMBER 31

(in thousands)	2008	2007	2006
Cash Flows from Operating Activities			
Net Income	$ 35,125	$ 53,961	$ 51,112
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Net Gain on Sale of Discontinued Operations	—	—	(336)
Income from Discontinued Operations	—	—	(26)
Depreciation and Amortization	65,060	52,830	49,983
Deferred Tax Credits	(1,692)	(1,169)	(1,146)
Deferred Income Taxes	40,665	4,366	(1,258)
Change in Deferred Debits and Other Assets	(41,851)	6,505	(38,499)
Discretionary Contribution to Pension Plan	(2,000)	(4,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	40,918	481	45,340
Allowance for Equity (Other) Funds Used During Construction	(2,786)	—	2,529
Change in Derivatives Net of Regulatory Deferral	1,044	(800)	3,083
Stock Compensation Expense	3,850	2,986	2,404
Other—Net	298	(1,837)	418
Cash Provided by (Used for) Current Assets and Current Liabilities:			
Change in Receivables	19,522	(18,903)	(15,713)
Change in Inventories	(743)	8,407	(14,345)
Change in Other Current Assets	(12,362)	(14,333)	(17,409)
Change in Payables and Other Current Liabilities	(8,572)	(2,556)	23,022
Change in Interest and Income Taxes Payable/Receivable	(25,155)	(1,126)	(5,952)
Net Cash Provided by Continuing Operations	111,321	84,812	79,207
Net Cash Provided by Discontinued Operations	—	—	1,039
Net Cash Provided by Operating Activities	111,321	84,812	80,246
Cash Flows from Investing Activities			
Capital Expenditures	(265,888)	(161,985)	(69,448)
Proceeds from Disposal of Noncurrent Assets	8,174	12,486	5,233
Acquisitions—Net of Cash Acquired	(41,674)	(6,750)	—
Net Decrease (Increase) in Other Investments	4	(7,745)	(3,326)
Net Cash Used in Investing Activities—Continuing Operations	(299,384)	(163,994)	(67,541)
Net Proceeds from Sale of Discontinued Operations	—	—	1,960
Net Cash Used in Investing Activities	(299,384)	(163,994)	(65,581)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	—	—	(11)
Net Short-Term Borrowings	39,914	56,100	22,900
Proceeds from Issuance of Common Stock	162,978	7,733	2,444
Common Stock Issuance Expenses	(6,418)	—	—
Payments for Retirement of Common Stock and Class B Stock of Subsidiary	(91)	(305)	(463)
Proceeds from Issuance of Long-Term Debt	1,240	205,129	149
Short-Term and Long-Term Debt Issuance Expenses	(1,252)	(1,762)	(458)
Payments for Retirement of Long-Term Debt	(3,639)	(118,171)	(3,287)
Dividends Paid	(38,093)	(35,516)	(34,621)
Net Cash Provided by (Used in) Financing Activities	154,639	113,208	(13,347)
Effect of Foreign Exchange Rate Fluctuations on Cash	1,165	(993)	43
Net Change in Cash and Cash Equivalents	(32,259)	33,033	1,361
Cash and Cash Equivalents at Beginning of Year—Continuing Operations	39,824	6,791	5,430
Cash and Cash Equivalents at End of Year—Continuing Operations	$ 7,565	$ 39,824	$ 6,791

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION, DECEMBER 31

(in thousands, except share data)		2008	2007
Long-Term Debt			
Senior Unsecured Notes 6.63%, due December 1, 2011		**$ 90,000**	$ 90,000
Senior Unsecured Note 5.778%, due November 30, 2017		**50,000**	50,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037		**50,000**	50,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027		**42,000**	42,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017		**33,000**	33,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022		**30,000**	30,000
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022		**20,625**	20,705
Pollution Control Refunding Revenue Bonds, Variable, 4.00% at December 31, 2008, due December 1, 2012		**10,400**	10,400
Lombard US Equipment Finance Note 6.76%, due October 2, 2010		**4,657**	6,986
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017		**5,165**	5,185
Obligations of Varistar Corporation—Various up to 9.69% at December 31, 2008		**7,982**	7,891
Total		**343,829**	346,167
Less:			
Current Maturities		**3,747**	3,004
Unamortized Debt Discount		**356**	469
Total Long-Term Debt		**339,726**	342,694
Class B Stock Options of Subsidiary		**1,220**	1,255
Cumulative Preferred Shares—Without Par Value (Stated and Liquidating Value $100 a Share)—Authorized 1,500,000 Shares; nonvoting and redeemable at the option of the Company			
Series Outstanding:	Call Price December 31, 2008		
$3.60, 60,000 Shares	$102.25	**6,000**	6,000
$4.40, 25,000 Shares	$102.00	**2,500**	2,500
$4.65, 30,000 Shares	$101.50	**3,000**	3,000
$6.75, 40,000 Shares	$101.6875	**4,000**	4,000
Total Preferred		**15,500**	15,500
Cumulative Preference Shares—Without Par Value, Authorized 1,000,000 Shares; Outstanding: None			
Total Common Shareholders' Equity		**676,018**	522,647
Total Capitalization		**$ 1,032,464**	$ 882,096

See accompanying notes to consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements of Otter Tail Corporation and its wholly-owned subsidiaries (the Company) include the accounts of the following segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. See note 2 to the consolidated financial statements for further descriptions of the Company's business segments. All significant intercompany balances and transactions have been eliminated in consolidation except profits on sales to the regulated electric utility company from nonregulated affiliates, which is in accordance with the requirements of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.*

REGULATION AND STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 71

As a regulated entity, the Company and the electric utility account for the financial effects of regulation in accordance with SFAS No. 71. This statement allows for the recording of a regulatory asset or liability for costs that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, the Company defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 4 for further discussion.

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

PLANT, RETIREMENTS AND DEPRECIATION

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $1,692,000 in 2008, $2,276,000 in 2007 and $202,000 in 2006. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.81% in 2008, 2.78% in 2007 and 2.82% in 2006. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at the then-current replacement cost if acquired in a business combination accounted for under the purchase method of accounting, and are depreciated on a straight-line basis over the assets' estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. The amount of interest capitalized on nonelectric plant was $465,000 in 2008, $390,000 in 2007 and $31,000 in 2006. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

JOINTLY OWNED PLANTS

The consolidated balance sheets include the Company's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the December 31, 2008 and 2007 consolidated balance sheets:

(in thousands)	2008	2007
Big Stone Plant:		
Electric Plant in Service	$ 135,623	$ 136,493
Accumulated Depreciation	(74,416)	(72,342)
Net Plant	$ 61,207	$ 64,151
Coyote Station:		
Electric Plant in Service	$ 148,109	$ 147,724
Accumulated Depreciation	(86,911)	(83,417)
Net Plant	$ 61,198	$ 64,307

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

RECOVERABILITY OF LONG-LIVED ASSETS

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

INCOME TAXES

Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes investment tax credits over the estimated lives of related property. The Company adopted Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, on January 1, 2007 and has recognized, in its consolidated financial statements, the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of December 31, 2008. The term "more-likely-than-not" means a likelihood of more than 50%. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 15 to the consolidated financial statements regarding the Company's accounting for uncertain tax positions.

REVENUE RECOGNITION

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as the electric utility's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with SFAS No. 133, *Accounting for*

Derivative Instruments and Hedging Activities, as amended and interpreted. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

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

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

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

The Company's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on the Company's consolidated statement of income. Under SFAS No. 133 as amended and interpreted, the Company's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. The Company is required to mark to market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts. See note 5 for further discussion.

Plastics operating revenues are recorded when the product is shipped.

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

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

Food Ingredient Processing revenues are recorded when the product is shipped.

Other Business Operations operating revenues are recorded when services are rendered or products are shipped. In the case of construction contracts, the percentage-of-completion method is used.

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company's consolidated revenues recorded under the percentage-of-completion method were 33.5% in 2008, 30.1% in 2007 and 25.1% in 2006. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company's wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	**December 31, 2008**	December 31, 2007
Costs Incurred on Uncompleted Contracts	$ 377,237	$ 286,358
Less Billings to Date	(366,931)	(292,692)
Plus Estimated Earnings Recognized	47,355	38,275
	$ 57,661	$ 31,941

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

(in thousands)	**December 31, 2008**	December 31, 2007
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 65,606	$ 42,234
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(7,945)	(10,293)
	$ 57,661	$ 31,941

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI) were $59,300,000 as of December 31, 2008 and $36,161,000 as of December 31, 2007. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

RETAINAGE

Accounts Receivable include amounts billed by the Company's subsidiaries under long-term contracts that have been retained by customers pending project completion of $10,311,000 on December 31, 2008 and $10,417,000 on December 31, 2007.

SALES OF RECEIVABLES

In March 2008, DMI, the Company's wind tower manufacturer, entered into a three-year $40 million receivable purchase agreement whereby designated customer accounts receivable may be sold to General Electric Capital Corporation on a revolving basis. Accounts receivable totaling $132,911,000 were sold in 2008. Discounts and commissions and fees of $722,000 for the year ended December 31, 2008 were charged to operating expenses in the consolidated statements of income. In compliance with SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, sales of accounts receivable are reflected as a reduction of accounts receivable in the consolidated balance sheets and the proceeds are included in the cash flows from operating activities in the consolidated statements of cash flows.

MARKETING AND SALES INCENTIVE COSTS

ShoreMaster, Inc. (ShoreMaster), the Company's waterfront equipment manufacturer, provides dealer floor plan financing assistance for certain dealer purchases of ShoreMaster products for certain set time periods based on the timing and size of a dealer's order. ShoreMaster recognizes the estimated cost of projected interest payments related to each financed sale as a liability and a reduction of revenue at the time of sale, based on historical experience of the average length of time floor plan debt is outstanding, in accordance with Emerging Issues Task Force Issue No. 01-9, *Accounting for Consideration Given by a Vendor to a Customer (Including a Reseller of a Vendor's Products)*. The liability is reduced when interest is paid. To the extent current experience differs from previous estimates the accrued liability for financing assistance costs is adjusted accordingly. Financing assistance costs of $500,000 for the year ended December 31, 2008 were charged to revenue.

FOREIGN CURRENCY TRANSLATION

The functional currency for the operations of the Canadian subsidiary of Idaho Pacific Holdings, Inc. (IPH) is the Canadian dollar (CAD). This subsidiary realizes foreign currency transaction gains or losses on settlement of receivables related to its sales, which are mostly in U.S. dollars (USD), and on exchanging U.S. currency for Canadian currency for its Canadian operations. This subsidiary recorded foreign currency transaction losses of $60,000 USD in 2008 as a result of the decrease in the value of the Canadian dollar relative to the U.S. dollar in 2008, and foreign currency transaction losses of $656,000 USD in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007. Transaction gains and losses in 2006 were not significant due to the relative stability of the currencies in 2006. The translation of CAD to USD is performed for balance sheet accounts using exchange rates in effect at the balance sheet dates, except for the common equity accounts which are at historical rates, and for revenue and expense accounts using a weighted average exchange during the year. Gains or losses resulting from the translation are included in Accumulated Other Comprehensive (Loss) Income in the equity section of the Company's consolidated balance sheet.

The functional currency for the Canadian subsidiary of DMI is the U.S. dollar. There are no foreign currency translation gains or losses related to this entity. However, this subsidiary may realize foreign currency transaction gains or losses on settlement of liabilities related to goods or services purchased in CAD. Foreign currency transaction gains related to balance sheet adjustments of CAD liabilities to USD equivalents and realized gains on settlement of those liabilities were $399,000 USD in 2008 as a result of the decrease in the value of the Canadian dollar relative to the U.S. dollar in 2008. Foreign currency transaction losses related to balance sheet adjustments of CAD liabilities to USD equivalents and realized losses on settlement of those liabilities were $102,000 USD in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007.

SHIPPING AND HANDLING COSTS

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

USE OF ESTIMATES

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

CASH EQUIVALENTS

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

SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

(in thousands)	2008	2007	2006
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$ (22,729)	$ 23,514	$ 1,401
Noncash Investing and Financing Transactions:			
Capital Leases	$ 2,084	—	—
Cash Paid During the Year from Continuing Operations for:			
Interest (net of amount capitalized)	$ 25,032	$ 18,155	$ 18,456
Income Taxes	$ 1,356	$ 25,906	$ 35,061
Cash Paid During the Year from Discontinued Operations for:			
Interest	$ —	$ —	$ 91
Income Taxes	$ —	$ —	$ 423

INVESTMENTS

The following table provides a breakdown of the Company's investments at December 31, 2008 and 2007:

(in thousands)	December 31, 2008	December 31, 2007
Cost Method:		
Economic Development Loan Pools	$ 528	$ 655
Other	1,057	1,303
Equity Method:		
Affordable Housing and Other Partnerships	1,441	1,851
Marketable Securities Classified as Available-for-Sale	4,516	6,248
Total Investments	$ 7,542	$ 10,057

The Company has investments in eleven limited partnerships that invest in tax-credit-qualifying affordable-housing projects that provided tax credits of $55,000 in 2008, $285,000 in 2007 and $839,000 in 2006. The Company owns a majority interest in eight of the eleven limited partnerships with a total investment of $1,426,000. FIN No. 46, *Consolidation of Variable Interest Entities*, requires full consolidation of the majority-owned partnerships. However, the Company includes these entities on its consolidated financial statements on a declining balance basis due to immateriality and uncertainty regarding residual values. Consolidating these entities would have represented less than 0.4% of total assets, 0.1% of total revenues and (0.5%) of operating income for the Company as of, and for the year ended, December 31, 2008 and would have an insignificant impact on the Company's 2008 consolidated net income.

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their market values on December 31, 2008. See further discussion below and under note 13.

FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company adopted SFAS No. 157, *Fair Value Measurements*, for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each level are as follows:

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

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

Level 3—Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of financial transmission rights.

The following table presents, for each of these hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2008:

(in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Investments for Nonqualified				
Retirement Savings Retirement Plan:				
Money Market and Mutual Funds				
and Cash	$ 890	$ —		$ 890
Cash Surrender Value of Life				
Insurance Policies		8,014		8,014
Cash Surrender Value of Keyman Life				
Insurance Policies—Net of Policy Loans		10,244		10,244
Forward Energy Contracts		405		405
Investments of Captive Insurance Company:				
Corporate Debt Securities	3,569			3,569
U.S. Government Debt Securities	947			947
Total Assets	$ 5,406	$18,663		$24,069
Liabilities:				
Forward Energy Contracts	$ —	$ 1,690	$ —	$ 1,690
Forward Foreign Currency				
Exchange Contracts	289			289
Asset Retirement Obligations			3,298	3,298
Total Liabilities	$ 289	$ 1,690	$ 3,298	$ 5,277
Net Assets (Liabilities)	$ 5,117	$16,973	$(3,298)	$18,792

INVENTORIES

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

(in thousands)	December 31, 2008	December 31, 2007
Finished Goods	$ 38,943	$ 38,952
Work in Process	10,205	5,218
Raw Material, Fuel and Supplies	52,807	53,044
Total Inventories	$ 101,955	$ 97,214

GOODWILL AND INTANGIBLE ASSETS

The Company accounts for goodwill and other intangible assets in accordance with the requirements of SFAS No. 142, *Goodwill and Other Intangible Assets*, requiring goodwill and indefinite-lived intangible assets to be measured for impairment at least annually and more often when events indicate the assets may be impaired. Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

As a result of the acquisition of Miller Welding & Iron Works, Inc. (Miller Welding) by BTD Manufacturing, Inc. (BTD) in May 2008, Goodwill increased $7,986,000, Covenants Not to Compete increased by $100,000, Customer Relationships increased by $16,100,000 and Brand/Trade Name increased by $400,000.

Changes in the carrying amount of Goodwill by segment are as follows:

(in thousands)	Balance December 31, 2007	Adjustment to Goodwill Related to Assets Sold in 2008	Goodwill Acquired in 2008	Balance December 31, 2008
Plastics	$ 19,302	$ —	$ —	$ 19,302
Manufacturing	16,746	—	7,986	24,732
Health Services	24,328	(450)	—	23,878
Food Ingredient Processing	24,324	—	—	24,324
Other Business Operations	14,542	—	—	14,542
Total	$ 99,242	$ (450)	$ 7,986	$106,778

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

2008 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Periods
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,250	$ 1,889	$ 361	3-5 years
Customer Relationships	26,854	2,429	24,425	15-25 years
Other Intangible Assets				
Including Contracts	2,710	1,921	789	5-30 years
Total	$31,814	$ 6,239	$25,575	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,866	$ —	$ 9,866	
2007 *(in thousands)*				
Amortized Intangible Assets:				
Covenants Not to Compete	$ 2,637	$ 2,113	$ 524	3-5 years
Customer Relationships	10,879	1,469	9,410	15-25 years
Other Intangible Assets				
Including Contracts	2,785	1,775	1,010	5-30 years
Total	$16,301	$ 5,357	$10,944	
Nonamortized Intangible Assets:				
Brand/Trade Name	$ 9,512	$ —	$ 9,512	

The amortization expense for these intangible assets was $1,464,000 for 2008, $1,227,000 for 2007 and $1,079,000 for 2006. The estimated annual amortization expense for these intangible assets for the next five years is $1,633,000 for 2009, $1,461,000 for 2010, $1,332,000 for 2011, $1,312,000 for 2012 and $1,308,000 for 2013.

NEW ACCOUNTING STANDARDS

SFAS No. 157, ***Fair Value Measurements***, was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. The adoption of SFAS No. 157 on January 1, 2008 resulted in additional footnote disclosures related to the use of fair value measurements in the areas of investments, derivatives, asset retirement obligations, goodwill and asset impairment evaluations, financial instruments and acquisitions, but did not have a significant impact on the Company's consolidated balance sheet, income statement or statement of cash flows.

SFAS No. 159, ***The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115***, was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company adopted SFAS No. 159 on January 1, 2008. The adoption of this pronouncement had no effect on the Company's consolidated financial statements because the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), *Business Combinations (SFAS No. 141(R))*, was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, Business Combinations, and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*, was issued by the FASB in March 2008. SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities to improve the transparency of financial reporting. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Adoption of SFAS No. 161 will result in additional footnote disclosures related to the Company's use of derivative instruments but those additional disclosures will not be extensive because the derivative instruments currently held by the Company are not designated as hedging instruments under SFAS No. 161.

2. BUSINESS COMBINATIONS, DISPOSITIONS AND SEGMENT INFORMATION

On May 1, 2008 BTD acquired the assets of Miller Welding of Washington, Illinois for $41.7 million in cash. Miller Welding, a custom job shop fabricator and finisher, recorded $26 million in revenue in 2007. Miller Welding manufactures and fabricates parts for off-road equipment, mining machinery, oil fields and offshore oil rigs, wind industry components, broadcast antennae and farm equipment, and serves several major equipment manufacturers in the Peoria, Illinois area and nationwide, including Caterpillar, Komatsu and Gardner Denver. This acquisition will provide opportunities for growth in new and existing markets for both BTD and Miller Welding, and complementing production capabilities will expand the scope and capacity of services offered by both companies.

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

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

Other Intangible Assets related to the Miller Welding acquisition include $16,100,000 for Customer Relationships being amortized over 20 years, $400,000 for a Nonamortizable Trade Name and a $100,000 Covenant Not to Compete being amortized over three years.

On February 19, 2007 ShoreMaster acquired the assets of the Aviva Sports product line for $2.0 million in cash. The Aviva Sports product line operates under Aviva Sports, Inc. (Aviva), a newly-formed wholly-owned subsidiary of ShoreMaster. The Aviva Sports product line is sold internationally and consists of products for consumer use in the pool, lake and yard, as well as commercial use at summer camps, resorts and large public swimming pools. The acquisition of the Aviva Sports product line fits well with the other product lines of ShoreMaster, a leading manufacturer and supplier of waterfront equipment.

On May 15, 2007 BTD acquired the assets of Pro Engineering, LLC (Pro Engineering) for $4.8 million in cash. Pro Engineering specializes in providing metal parts stampings to customers in the Midwest. The acquisition of Pro Engineering by BTD provides expanded growth opportunities for both companies.

Below, are condensed balance sheets, at the dates of the respective business combinations, disclosing the allocation of the purchase price assigned to each major asset and liability category of Aviva and Pro Engineering:

(in thousands)	**Aviva**	**Pro Engineering**
Assets		
Current Assets	$ 2,083	$ 1,956
Goodwill	—	1,048
Other Intangible Assets	870	396
Plant	—	1,600
Total Assets	$ 2,953	$ 5,000
Liabilities		
Current Liabilities	$ 988	$ 215
Noncurrent Liabilities	—	—
Total Liabilities	$ 988	$ 215
Cash Paid	$ 1,965	$ 4,785

Other Intangible Assets related to the Aviva acquisition include $83,000 for a nonamortizable brand name and $787,000 in intangible assets being amortized over various periods up to 15 years. Other Intangible Assets related to the Pro Engineering acquisition include $51,000 for a nonamortizable brand name and $345,000 in intangible assets being amortized over various periods up to 20 years.

The Company acquired no new businesses in 2006.

All of the acquisitions described above were accounted for using the purchase method of accounting. Disclosure of pro forma information related to the results of operations of the entities acquired in 2008 and 2007 for the periods presented in this report is not required due to immateriality.

In June 2006, Otter Tail Energy Services Company (OTESCO), the Company's energy services company, sold its gas marketing operations. Discontinued Operations includes the operating results of OTESCO's natural gas marketing operations and an after-tax gain on the sale of its natural gas marketing operations of $0.3 million in 2006.

SEGMENT INFORMATION

The accounting policies of the segments are described under note 1—Summary of Significant Accounting Policies. The Company's businesses have been classified into six segments based on products and services and reach customers in all 50 states and international markets. The six segments are: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company (the electric utility). In addition, the electric 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 consists of businesses producing polyvinyl chloride 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 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.

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 4 Canadian provinces.

Our electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation, and our energy services operation is operated as a subsidiary of Otter Tail Corporation. Substantially all of our other businesses are owned by our wholly owned subsidiary Varistar Corporation.

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

The Company has one customer within the Manufacturing segment that accounted for approximately 10.6% of the Company's consolidated revenues in 2008. No other single external customer accounts for 10% or more of the Company's revenues. Substantially all of the Company's long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Fort Erie, Ontario, Canada.

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

	2008	2007	2006
United States of America	**97.3%**	96.9%	97.2%
Canada	**1.1%**	1.3%	1.3%
All Other Countries	**1.6%**	1.8%	1.5%

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for 2008, 2007 and 2006 is presented in the following table.

(in thousands)	**2008**	2007	2006
Operating Revenue			
Electric	**$ 340,020**	$ 323,478	$ 306,014
Plastics	**116,452**	149,012	163,135
Manufacturing	**470,462**	381,599	311,811
Health Services	**122,520**	130,670	135,051
Food Ingredient Processing	**65,367**	70,440	45,084
Other Business Operations	**199,511**	185,730	145,603
Corporate and Intersegment Eliminations	**(3,135)**	(2,042)	(1,744)
Total	**$1,311,197**	$1,238,887	$1,104,954
Depreciation and Amortization			
Electric	**$ 31,755**	$ 26,097	$ 25,756
Plastics	**3,050**	3,083	2,815
Manufacturing	**19,260**	13,124	11,076
Health Services	**4,133**	3,937	3,660
Food Ingredient Processing	**4,094**	3,952	3,759
Other Business Operations	**2,230**	2,058	2,330
Corporate	**538**	579	587
Total	**$ 65,060**	$ 52,830	$ 49,983
Interest Charges			
Electric	**$ 12,895**	$ 9,405	$ 10,315
Plastics	**1,156**	970	814
Manufacturing	**8,666**	8,546	6,550
Health Services	**714**	883	910
Food Ingredient Processing	**109**	177	481
Other Business Operations	**1,171**	1,234	988
Corporate and Intersegment Eliminations	**2,247**	(358)	(557)
Total	**$ 26,958**	$ 20,857	$ 19,501
Income Before Income Taxes			
Electric	**$ 46,160**	$ 37,422	$ 38,802
Plastics	**3,114**	13,452	22,959
Manufacturing	**7,650**	24,503	21,148
Health Services	**342**	2,626	3,909
Food Ingredient Processing	**2,655**	5,912	(6,325)
Other Business Operations	**8,736**	6,762	8,666
Corporate	**(18,495)**	(8,748)	(11,303)
Total	**$ 50,162**	$ 81,929	$ 77,856
Earnings Available for Common Shares			
Electric	**$ 32,498**	$ 23,762	$ 23,445
Plastics	**1,880**	8,314	14,326
Manufacturing	**5,269**	15,632	13,171
Health Services	**85**	1,427	2,230
Food Ingredient Processing	**1,681**	4,386	(4,115)
Other Business Operations	**5,279**	4,049	5,257
Corporate	**(12,303)**	(4,345)	(4,300)
Total	**$ 34,389**	$ 53,225	$ 50,014
Capital Expenditures			
Electric	**$ 198,798**	$ 104,288	$ 35,207
Plastics	**8,883**	3,305	5,504
Manufacturing	**47,606**	42,786	20,048
Health Services	**4,039**	5,276	4,720
Food Ingredient Processing	**2,402**	47	1,762
Other Business Operations	**3,919**	5,589	1,779
Corporate	**241**	694	428
Total	**$ 265,888**	$ 161,985	$ 69,448
Identifiable Assets			
Electric	**$ 992,159**	$ 813,565	$ 689,653
Plastics	**78,054**	77,971	80,666
Manufacturing	**356,697**	274,780	219,336
Health Services	**61,086**	64,824	66,126
Food Ingredient Processing	**88,813**	91,966	94,462
Other Business Operations	**71,359**	72,258	67,110
Corporate	**44,419**	59,390	41,008
Discontinued Operations	**—**	—	289
Total	**$1,692,587**	$1,454,754	$1,258,650

3. RATE AND REGULATORY MATTERS

MINNESOTA

General Rate Case— In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 the electric 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 electric 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 electric 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 electric 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.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need—On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt (kv) transmission lines. 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 Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. Otter Tail Power Company 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 electric utility filed a Certificate of Need for the fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (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.

Renewable Energy Standards, Conservation and Renewable Resource Riders—In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric 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 electric 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 electric utility expects to have sufficient renewable energy resources available to comply with the required 2012 level of the Minnesota renewable energy standard. The electric 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 passed by the Minnesota legislature in May 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 electric 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 electric 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 kilowatt-hour (kwh) was included on Minnesota customers' electric service statements beginning in September 2008. The first renewable energy project for which the electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric 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 electric 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 electric 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 electric utility expects to file a proposed rider with the MPUC to recover its share of costs of eligible transmission infrastructure upgrades projects in 2009.

Recovery of MISO Costs—In December 2005, the MPUC issued an order denying the electric utility's request to allow recovery of certain MISO-related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The electric 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 Minnesota Department of Commerce (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 electric 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 electric 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 electric 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.

Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report)—The MNDOC and the electric 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 (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 the electric 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 AAA Report. The electric 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 electric utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. The electric utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the electric utility's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, the electric 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.

Claims of Improper Regulatory Filings—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 electric 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 electric 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 electric utility to include all of the Company's short-term debt in its calculations of allowance for funds used during construction (AFUDC) and the electric utility agreed to provide the MPUC the results of an ongoing FERC operational audit when available. The Company recorded a noncash charge to Other Income and Deductions of $3.3 million in 2006 related to the disallowance of a portion of capitalized AFUDC from the electric utility's rate base as a result of including all of the Company's short-term debt, regardless of use, in the electric utility's calculations 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 electric utility's recent general rate case. FERC Order (IN08-6-000), resolving alleged network transmission service violations by the electric 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

General Rate Case—On November 3, 2008 the electric 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 North Dakota Public Service Commission (NDPSC) on the electric 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 electric utility's request. If final rates are lower than interim rates, the electric utility will refund North Dakota customers the difference with interest.

Renewable Resource Cost Recovery Rider—On May 21, 2008 the NDPSC approved the electric utility's request for a Renewable Resource Cost Recovery Rider to enable the electric 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 electric utility will receive cost recovery is its 40.5 megawatt ownership share of the Langdon Wind Energy Center, which became fully operational in January 2008. The electric utility may also recover through this rider costs associated with other new renewable energy projects as they are completed. The electric 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 electric 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 electric 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 electric utility has requested recovery of such costs in its general rate case filed in November 2008.

Recovery of MISO Costs—In February 2005, the electric 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 electric utility and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, the electric 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 electric 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 electric 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. Requests 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.

SOUTH DAKOTA

General Rate Case—On October 31, 2008 the electric 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 electric utility's request is expected in mid-summer 2009.

FEDERAL

Revenue Sufficiency Guarantee (RSG) Charges—On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time 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 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 electric 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 electric 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 electric utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the electric utility. Accordingly, the electric 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 as 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 electric 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 electric 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 electric utility will likely seek review at the District of Columbia Circuit (D.C. Circuit). The electric 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 electric utility to further RSG refunds and resettlements prior to August 10, 2007.

Since 2006, the electric 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 United States Court of Appeals for the D.C. Circuit. These proceedings create potential contingent liabilities in three separate periods for the electric utility: (1) April 1, 2005 through April 24, 2006; (2) April 25, 2006 through August 9, 2007; and (3) August 10, 2007 forward. The electric 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 electric 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.

Transmission Practices Audit—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 electric utility's transmission practices for the period January 1, 2003 through August 31, 2005. The purpose of the audit was to determine whether the electric utility's transmission practices were in compliance with the FERC's applicable rules, regulations and tariff requirements and whether the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 appropriately restricted access to transmission information that would benefit the electric utility's off-system sales. FERC staff identified two of the electric utility's transmission practices that it believed were out of compliance. The electric 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.

FERC Order (IN08-6-000) issued May 29, 2008 resolves alleged network transmission service violations by the electric utility of MISO's TEMT. The electric 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 electric utility. This amount represents profits earned by the electric 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 electric utility because the MISO's Day 2 market is now operational and its member utilities no longer schedule transmission within the system.

BIG STONE II PROJECT

On June 30, 2005 the electric 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 megawatts to between 500 and 580 megawatts. 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.

In the fourth quarter of 2005, the participating utilities filed applications with the MPUC for a transmission Certificate of Need and a Route Permit for the Minnesota portion of the Big Stone II transmission line. 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;
- 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 cost at $3000/kilowatt and carbon dioxide 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 electric utility's integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. On June 5, 2008 the MPUC deferred approval of the electric utility's 2006-2020 IRP, originally filed in 2005. The addition of 160 megawatts of wind generation in the IRP was approved early in 2007 and, on January 15, 2009, the MPUC approved the electric 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.

On August 27, 2008 the NDPSC determined that the electric utility's participation in Big Stone II was prudent in a range of 121.8 to 130 megawatts. The NDPSC decision has been appealed to Burleigh County District Court by interveners in the matter. 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.

The Big Stone II 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 electric utility anticipates publication of the ROD in the Federal Register in the second quarter of 2009. 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. No one can predict the exact outcome of any of these proceedings.

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 electric utility has experienced more rapid load growth than was expected since originally filing the IRP in 2005. The electric 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 megawatts of peaking capacity. The MPUC committed to expediting a decision on this request.

As of December 31, 2008 the electric utility has 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.

4. REGULATORY ASSETS AND LIABILITIES

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

(in thousands)	**December 31, 2008**	December 31, 2007
Regulatory Assets:		
Unrecognized Prior Service Costs and Actuarial Losses on Pension Benefits	$ 64,490	$ 26,933
Accrued Cost-of-Energy Revenue	8,982	19,452
Deferred Income Taxes	7,094	8,733
Debt Reacquisition Premiums	3,357	3,745
Minnesota Renewable Resource Rider Accrued Revenues	3,045	—
North Dakota Renewable Resource Rider Accrued Revenues	2,009	—
Minnesota General Rate Case Recoverable Expenses	1,457	—
Accumulated ARO Accretion/Depreciation Adjustment	1,437	345
Deferred Marked-to-Market Losses	1,162	771
MISO Schedule 16 and 17 Deferred Administrative Costs—ND	823	576
MISO Schedule 16 and 17 Deferred Administrative Costs—MN	526	855
Deferred Conservation Improvement Program Costs	280	518
Plant Acquisition Costs	63	107
Total Regulatory Assets	$ 94,725	$ 62,035
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 58,768	$ 57,787
Deferred Income Taxes	4,943	4,502
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Gains on Other Postretirement Benefits	834	—
Deferred Marked-to-Market Gains	—	271
Gain on Sale of Division Office Building	139	145
Total Regulatory Liabilities	$ 64,684	$ 62,705
Net Regulatory Asset (Liability) Position	$ 30,041	$ (670)

The regulatory asset related to prior service costs and actuarial losses on pension benefits and the regulatory liability related to the unrecognized transition obligation, prior service costs and actuarial gains on other postretirement benefits represents benefit costs and actuarial gains subject to recovery or return through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial gains were required to be recognized as components of Accumulated Other Comprehensive Income in equity under SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next 20 months.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*.

Debt Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 23.7 years.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve Minnesota customers since January 1, 2008 that have not been billed to Minnesota customers as of December 31, 2008. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 15 months, from January 2009 through March 2010.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 renewable resource costs incurred to serve North Dakota customers since January 1, 2008 that have not been billed to North Dakota customers as of December 31, 2008. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 13 months, from January 2009 through January 2010.

Minnesota General Rate Case Recoverable Expenses will be recovered over a 36-month period beginning in February 2009 when revised rates established by the recent Minnesota general rate case go into effect.

The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred.

All Deferred Marked-to-Market Losses recorded as of December 31, 2008 are related to forward purchases of energy scheduled for delivery prior to March 2009.

MISO Schedule 16 and 17 Deferred Administrative Costs—ND will be recovered over the next 36 months.

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

Plant Acquisition Costs will be amortized over the next 17 months.

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

The remaining regulatory liabilities will be paid to electric customers over the next 30 years.

If for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

5. FORWARD CONTRACTS CLASSIFIED AS DERIVATIVES

ELECTRICITY CONTRACTS

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

Electric revenues include $27,236,000 in 2008, $25,640,000 in 2007 and $25,965,000 in 2006 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts and sales of financial transmission rights and daily settlements of virtual transactions in the MISO market, broken down as follows for the years ended December 31:

(in thousands)	**2008**	2007	2006
Wholesale Sales—Company-Owned Generation	**$ 23,708**	$ 20,345	$ 23,130
Revenue from Settled Contracts at Market Prices	**520,280**	389,643	385,978
Market Cost of Settled Contracts	**(518,866)**	(387,682)	(383,594)
Net Margins on Settled Contracts at Market	**1,414**	1,961	2,384
Marked-to-Market Gains on Settled Contracts	**39,375**	31,243	20,950
Marked-to-Market Losses on Settled Contracts	**(37,138)**	(28,541)	(20,702)
Net Marked-to-Market Gain on Settled Contracts	**2,237**	2,702	248
Unrealized Marked-to-Market Gains on Open Contracts	**405**	5,117	2,215
Unrealized Marked-to-Market Losses on Open Contracts	**(528)**	(4,485)	(2,012)
Net Unrealized Marked-to-Market (Loss) Gain on Open Contracts	**(123)**	632	203
Wholesale Electric Revenue	**$ 27,236**	$ 25,640	$ 25,965

The following tables show the effect of marking to market forward contracts for the purchase and sale of energy on the Company's consolidated balance sheets:

(in thousands)	**December 31, 2008**	December 31, 2007
Current Asset—Marked-to-Market Gain	**$ 405**	$ 5,210
Regulatory Asset—Deferred Marked-to-Market Loss	**1,162**	771
Total Assets	**1,567**	5,981
Current Liability—Marked-to-Market Loss	**(1,690)**	(5,078)
Regulatory Liability—Deferred Marked-to-Market Gain	**—**	(271)
Total Liabilities	**(1,690)**	(5,349)
Net Fair Value of Marked-to-Market Energy Contracts	**$ (123)**	$ 632

(in thousands)	**Year ended December 31, 2008**
Fair Value at Beginning of Year	$ 632
Amount Realized on Contracts Entered into in 2007 and Settled in 2008	(1,169)
Changes in Fair Value of Contracts Entered into in 2007	537
Net Fair Value of Contracts Entered into in 2007 at Year End 2008	—
Changes in Fair Value of Contracts Entered into in 2008	(123)
Net Fair Value at End of Year	$ (123)

The $123,000 in recognized but unrealized net losses on the forward energy purchases and sales marked to market as of December 31, 2008 is expected to be realized on settlement as scheduled in January and February of 2009.

Of the forward energy sales contracts that are marked to market as of December 31, 2008, 100% are offset by forward energy purchase contracts in terms of volumes and delivery periods.

NATURAL GAS CONTRACTS

In order to limit its exposure to fluctuations in future prices of natural gas, IPH entered into contracts with its natural gas suppliers in August 2008 for the firm purchase of natural gas to cover portions of its anticipated natural gas needs in Ririe, Idaho and Center, Colorado from September 2008 through August 2009 at fixed prices. These contracts qualify for the normal purchase exception to mark-to-market accounting under SFAS 133, as amended by SFAS 138.

FOREIGN CURRENCY EXCHANGE FORWARD WINDOWS

The Canadian operations of IPH records its sales and carries its receivables in U.S. dollars but pays its expenses for goods and services consumed in Canada in Canadian dollars. The payment of its bills in Canada requires the periodic exchange of U.S. currency for Canadian currency. In order to lock in acceptable exchange rates and hedge its exposure to future fluctuations in foreign currency exchange rates between the U.S. dollar and the Canadian dollar, IPH's Canadian subsidiary entered into forward contracts for the exchange of U.S. dollars into Canadian dollars in 2008. Each monthly contract was for the exchange of $400,000 U.S. dollars for the amount of Canadian dollars stated in each contract. The total amounts of contracts settled in 2008 and outstanding on December 31, 2008 along with net exchange losses realized in 2008 and recognized as of December 31, 2008 are presented in the following table:

(in thousands)	Settlement Periods	USD	CAD
Contracts entered into in March 2008	April 2008-December 2008	$ 3,600	$ 3,695
Net Mark-to-Market Losses Realized on Settlement	April 2008-December 2008	(224)	
Contracts entered into in July 2008	August 2008-July 2009	$ 4,800	$ 5,003
Net Mark-to-Market Losses Realized on Settlement	August 2008-December 2008	(203)	
Mark-to-Market Losses on Open Contracts at Year End 2008	January 2009-July 2009	(401)	
Contracts entered into in October 2008	January 2009-October 2009	$ 4,000	$ 5,001
Mark-to-Market Gains on Open Contracts at Year End 2008	January 2009-October 2009	112	
Net Mark-to-Market Losses Realized on Settlement in 2008		$ (427)	
Net Mark-to-Market Losses Recognized on Open Contracts at Year End 2008		(289)	
Net Mark-to-Market Losses Recognized in 2008		$ (716)	

These contracts are derivatives subject to mark-to-market accounting. IPH does not enter into these contracts for speculative purposes or with the intent of early settlement, but for the purpose of locking in acceptable exchange rates and hedging its exposure to future fluctuations in exchange rates with the intent of settling these contracts during their stated settlement periods and using the proceeds to pay its Canadian liabilities when they come due. These contracts do not qualify for hedge accounting treatment because the timing of their settlements did not and will not coincide with the payment of specific bills or existing contractual obligations. The foreign currency exchange forward contracts outstanding as of December 31, 2008 were valued and marked to market on December 31, 2008 based on quoted exchange values of similar contracts that could be purchased on December 31, 2008.

The fair value measurements of the above foreign currency exchange forward windows fall into level 1 of the fair value hierarchy set forth in SFAS No. 157.

6. COMMON SHARES AND EARNINGS PER SHARE

Following is a reconciliation of the Company's common shares outstanding from December 31, 2007 through December 31, 2008:

Common Shares Outstanding, December 31, 2007	29,849,789
Issuances:	
September 2008 Common Stock Offering	5,175,000
Stock Options Exercised	276,685
Executive Officer Stock Performance Awards	62,625
Restricted Stock Issued to Nonemployee Directors	20,000
Restricted Stock Issued to Employees	19,371
Vesting of Restricted Stock Units	3,850
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(22,700)
Common Shares Outstanding, December 31, 2008	35,384,620

In September 2008 the Company completed a public offering of 5,175,000 common shares under its universal shelf registration statement filed with the Securities and Exchange Commission, including 675,000 common shares issued pursuant to the full exercise of the underwriters' overallotment option. The public offering price was $30 per share. Net proceeds from the sale of the common shares after deducting underwriting discounts and commissions and offering expenses were $148.8 million. The net proceeds were used to finance the construction of Otter Tail Power Company's 32 wind turbines and collector system at the Ashtabula Wind Center in Barnes County, North Dakota and the expansion of DMI's wind tower manufacturing facilities in Tulsa, Oklahoma and West Fargo, North Dakota.

STOCK INCENTIVE PLAN

The 1999 Stock Incentive Plan, as amended (Incentive Plan), provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 3,600,000 common shares are authorized for granting stock awards, of which 1,017,326 were still available as of December 31, 2008 under the Incentive Plan, which terminates on December 13, 2013.

EMPLOYEE STOCK PURCHASE PLAN

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 330,565 were still available for purchase as of December 31, 2008. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, 49,684 common shares were purchased in the open market in 2008, 52,558 common shares were purchased in the open market in 2007 and 53,258 common shares were purchased in the open market in 2006. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive for the purpose of calculating diluted earnings per share during the investment period.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

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

EARNINGS PER SHARE

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

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the years ended December 31, 2008, 2007 and 2006:

Year	Options Outstanding	Range of Exercise Prices
2008	—	NA
2007	—	NA
2006	210,250	$29.74—$31.34

7. SHARE-BASED PAYMENTS

PURCHASE PLAN

The Purchase Plan allows employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under SFAS No. 123 (revised 2004), *Share-Based Payments* (SFAS No. 123(R)), the Company is required to record compensation expense related to the 15% discount. The 15% discount resulted in compensation expense of $275,000 in 2008, $257,000 in 2007 and $235,000 in 2006. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

STOCK OPTIONS GRANTED UNDER THE INCENTIVE PLAN

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company's common stock. All of the options granted had vested or were forfeited as of December 31, 2007. The exercise price of the options granted was the average market price of the Company's common stock on the grant date. Under SFAS No. 123(R) accounting, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under SFAS No. 123(R) accounting, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan has been based on the Black-Scholes option pricing model.

Under the modified prospective application of SFAS No. 123(R) accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of $362,000 on January 1, 2006 was recognized on a straight-line basis as compensation expense over the remaining 16 months of the options vesting period. Accordingly, the Company recorded compensation expense of $91,000 in 2007 and $271,000 in 2006 related to options that were not vested as of January 1, 2006.

Presented below is a summary of the stock options activity:

Stock Option Activity	2008 Options	2008 Average Exercise Price	2007 Options	2007 Average Exercise Price	2006 Options	2006 Average Exercise Price
Outstanding, Beginning of Year	787,137	$ 25.73	1,091,238	$ 25.74	1,237,164	$ 25.58
Granted	—	—	—	—	—	—
Exercised	276,685	25.23	298,601	25.73	107,458	22.88
Forfeited	2,750	27.11	5,500	28.85	38,468	28.60
Outstanding, End of Year	507,702	26.00	787,137	25.73	1,091,238	25.74
Exercisable, End of Year	507,702	26.00	787,137	25.73	1,049,713	25.69
Cash Received for Options Exercised	$ 6,981,000		$ 7,682,000		$ 2,458,000	
Fair Value of Options Granted During Year	none granted		none granted		none granted	

The following table summarizes information about options outstanding as of December 31, 2008:

Options Outstanding and Exercisable			
Range of Exercise Prices	Outstanding and Exercisable as of 12/31/08	Weighted-Average Remaining Contractual Life (yrs)	Weighted-Average Exercise Price
$18.80–$21.94	87,242	1.1	$ 19.69
$21.95–$25.07	28,300	6.3	24.93
$25.08–$28.21	307,010	2.9	26.48
$28.22–$31.34	85,150	3.2	31.06

RESTRICTED STOCK GRANTED TO DIRECTORS

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under the application of SFAS No. 123(R) accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 14, 2008 the Company's Board of Directors granted 20,000 shares of restricted stock to the Company's nonemployee directors. The restricted shares vest 25% per year on April 8 of each year in the period 2009 through 2012 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $35.345 per share, the average market price on the date of grant.

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

Directors' Restricted Stock Awards	**2008**		2007		2006	
	Shares	**Weighted Average Grant-Date Fair Value**	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	**34,100**	**$ 30.80**	32,775	$ 27.27	27,000	$ 26.32
Granted	**20,000**	**35.345**	15,200	35.04	19,800	28.24
Vested	**14,800**	**29.92**	13,875	27.10	14,025	26.82
Forfeited	**—**		—		—	
Nonvested, End of Year	**39,300**	**33.45**	34,100	30.80	32,775	27.27
Compensation Expense Recognized		**$ 461,000**		$ 454,000		$ 401,000
Fair Value of Shares Vested in Year		**443,000**		376,000		376,000

RESTRICTED STOCK GRANTED TO EMPLOYEES

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Because of income tax withholding provisions in the restricted stock award agreements related to restricted stock granted to employees prior to 2006, the value of these grants is considered variable, which, under SFAS No. 123(R), requires the offsetting credit to compensation expense to be recorded as a liability. Under the modified prospective application of SFAS No. 123(R) accounting requirements and accounting rules for variable awards, compensation expense related to nonvested restricted shares granted to employees is recorded based on the estimated fair value of the restricted shares on their grant dates and adjusted for the estimated fair value of any nonvested restricted shares on each subsequent reporting date. The reporting date fair value of nonvested restricted shares granted prior to 2006 under this program is based on the average market value of the Company's common stock on the reporting date—$23.15 on December 31, 2008.

In 2006, under SFAS No. 123(R), the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the estimated fair value of the restricted stock grants. Under SFAS 123(R) accounting, a current liability account is credited when compensation expense is recorded. Accumulated liabilities related to nonvested restricted shares issued to employees under this program prior to 2006 will be reversed and credited to the Premium on Common Shares equity account as the shares vest.

The fair value of restricted shares issued under the revised restricted stock award agreements is not considered a liability under SFAS No. 123(R), so compensation expense related to awards granted is based on their grant-date fair value and recognized over the vesting period of the awards with the offsetting credit charged directly to equity.

On April 14, 2008 the Company's Board of Directors granted 17,600 shares of restricted stock to the Company's executive officers and 1,771 shares of restricted stock to a key employee under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2009 through 2012 and are eligible for full dividend and voting rights. The grant date fair value of each share of restricted stock was $35.345 per share, the average market price on the date of grant.

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

Employees' Restricted Stock Awards	**2008**		2007		2006	
	Shares	**Weighted Average Fair Value**	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Nonvested, Beginning of Year	**24,058**	**$ 35.46**	31,666	$ 31.47	72,974	$ 28.91
Granted	**19,371**	**35.345**	17,300	35.82	—	
Variable/Liability Awards Vested	**4,808**	**34.85**	24,608	35.09	41,308	28.98
Nonvariable Awards Vested	**4,475**	**35.80**	300	35.30	—	
Forfeited	**—**		—		—	
Nonvested, End of Year	**34,146**	**34.72**	24,058	35.46	31,666	31.47
Compensation Expense Recognized		**$ 434,000**		$ 549,000		$ 815,000
Fair Value of Variable Awards Vested/Liability Paid		**168,000**		863,000		1,197,000
Fair Value of Nonvariable Awards Vested		**160,000**		11,000		—

RESTRICTED STOCK UNITS GRANTED TO EMPLOYEES

On April 14, 2008 the Company's Board of Directors granted 26,050 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2012, the date the units vest. The grant date fair value of each restricted stock unit was $30.81 per share. Also on April 14, 2008 the Company's Board of Directors approved the award of 600 restricted stock units to be granted effective July 1, 2008 for another key employee under the Incentive Plan payable in common shares on July 1, 2011, the date the units vest. The grant date fair value of these restricted stock units was $35.55 per share. The weighted average contractual term of stock units outstanding as of December 31, 2008 is 2.6 years.

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

Employees' Restricted Stock Unit Awards	**2008**		2007		2006	
	Restricted Stock Units	**Weighted Average Grant-Date Fair Value**	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	**55,480**	**$ 26.66**	38,615	$ 24.65	—	$ —
Granted	**26,650**	**30.92**	23,450	30.07	47,425	25.41
Converted	**3,850**	**25.93**	4,850	26.95	7,450	29.55
Forfeited	**4,695**	**28.07**	1,735	27.03	1,360	24.36
Nonvested, End of Year	**73,585**	**28.13**	55,480	26.66	38,615	24.65
Compensation Expense Recognized		**$ 535,000**		$ 383,000		$ 427,000
Fair Value of Units Converted in Year		**100,000**		131,000		220,000

STOCK PERFORMANCE AWARDS GRANTED TO EXECUTIVE OFFICERS

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under SFAS No. 123(R) accounting requirements, the amount of compensation expense recorded related to awards granted is based on the estimated grant-date fair value of the awards as determined under a Monte Carlo valuation method.

On April 14, 2008 the Company's Board of Directors granted performance share awards to the Company's executive officers under the Incentive Plan for the 2008-2010 performance measurement period.

The offsetting credit to amounts expensed related to the stock performance awards is included in common shareholders' equity. The table below provides a summary of stock performance awards granted and amounts expensed related to the stock performance awards:

Performance Period	**Maximum Shares Subject To Award**	**Shares Used To Estimate Expense**	**Fair Value**	**Expense Recognized in the Year Ended December 31,**			**Shares Awarded**
				2008	**2007**	**2006**	
2008-2010	114,800	70,843	$ 37.59	**$ 888,000**	$ —	$ —	
2007-2009	109,000	67,263	$ 38.01	**852,000**	852,000	—	
2006-2008	88,050	58,700	$ 25.95	**508,000**	508,000	508,000	29,350
2005-2007	75,150	50,872	$ 22.10	**—**	375,000	375,000	62,625
2004-2006	70,500	23,500	$ 23.90	**—**	—	187,000	23,500
Total				**$ 2,248,000**	$ 1,735,000	$ 1,070,000	115,475

As of December 31, 2008 the total remaining unrecognized amount of compensation expense related to stock-based compensation for all stock-based payment programs was approximately $5.8 million (before income taxes), which will be amortized over a weighted-average period of 2.2 years.

8. RETAINED EARNINGS RESTRICTION

The Company's Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company's cumulative preferred shares. Under these provisions none of the Company's retained earnings were restricted at December 31, 2008.

9. COMMITMENTS AND CONTINGENCIES

ELECTRIC UTILITY CONSTRUCTION CONTRACTS, CAPACITY AND ENERGY REQUIREMENTS AND COAL AND DELIVERY CONTRACTS

At December 31, 2008 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $30,210,000. For capacity and energy requirements, the electric utility has agreements extending through 2032 at annual costs of approximately $23,846,000 in 2009, $11,552,000 in 2010, $5,565,000 in 2011, $5,565,000 in 2012 and $5,556,000 in 2013, and $87,729,000 for the years beyond 2013.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $153,988,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

IPH POTATO SUPPLY AND FUEL PURCHASE COMMITMENTS

IPH has commitments of approximately $9,810,000 for the purchase of a portion of its 2009 raw potato supply requirements and $1,885,000 for the firm purchase of natural gas and fuel oil to cover portions of its anticipated fuel needs in Ririe, Idaho, Center, Colorado and Souris, Prince Edward Island, Canada through August 2009.

OPERATING LEASE COMMITMENTS

The amounts of future operating lease payments are as follows:

(in thousands)	Electric	Nonelectric	Total
2009	$ 2,826	$ 43,398	$ 46,224
2010	2,469	33,183	35,652
2011	1,712	19,617	21,329
2012	1,216	9,844	11,060
2013	1,216	4,728	5,944
Later years	2,836	7,003	9,839
Total	$ 12,275	$ 117,773	$ 130,048

The electric future operating lease payments are primarily related to coal rail-car leases. The nonelectric future operating lease payments are primarily related to medical imaging equipment. Rent expense from continuing operations was $50,761,000, $47,904,000 and $44,254,000 for 2008, 2007 and 2006, respectively.

DEALER FLOOR PLAN FINANCING

Under ShoreMaster's floor plan financing agreement with GE Commercial Distribution Finance Corporation (CDF), ShoreMaster is required to repurchase new and unused inventory repossessed from ShoreMaster's dealers by CDF to satisfy dealer obligations to CDF. ShoreMaster has agreed to unconditionally guarantee to CDF all current and future liabilities which any dealer owes to CDF under this agreement. Any amounts due under this guaranty will be payable despite impairment or unenforceability of CDF's security interest with respect to inventory that may prevent CDF from repossessing the inventory. The aggregate total of amounts owed by dealers to CDF under this agreement was $5.0 million on December 31, 2008. ShoreMaster has incurred no losses under this agreement. The Company believes current available cash and cash generated from operations provide sufficient funding in the event there is a requirement to perform under this agreement. CDF has notified ShoreMaster it is exercising its right under this agreement to terminate the agreement effective February 28, 2009. The termination of the agreement will have no affect on ShoreMaster's obligations to CDF for any products financed, advances made or approvals granted by CDF under the agreement prior to the effective termination date. Additionally, ShoreMaster is liable for any expenses incurred by CDF before or after the effective termination date in connection with the collection of any amounts or other charges as set forth in the agreement.

SIERRA CLUB COMPLAINT

On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The complaint 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 electric 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 electric 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 electric 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 electric utility. The electric 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 electric 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 electric utility's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, the electric utility filed a Reply, denying the allegations made by RES and PEAK Wind in its Answer. By Order issued on December 19, 2008, the FERC set the Complaint for hearing and established settlement procedures. The parties are engaged in settlement discussions. The Company believes the claims that the electric utility has violated the FPA are without merit. The ultimate outcome of this matter cannot be determined at this time.

PRODUCT RECALL

Aviva Sports, Inc. (Aviva), a subsidiary of ShoreMaster, markets a variety of consumer products to catalog companies and internet based retailers. Some of these products are regulated by the U.S. Consumer Product Safety Commission (CPSC). On February 3, 2009 Aviva received a report of consumer contacts from a catalog customer related to one of Aviva's trampoline products. Aviva has not received any personal injury claims or lawsuits related to this product. Aviva submitted notification of the complaints to the CPSC and voluntarily agreed to undertake a recall of approximately 12,000 of the trampoline products. The Company does not expect the costs of this recall to have a material effect on its consolidated financial position or results of operations.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2008 will not be material.

10. SHORT-TERM AND LONG-TERM BORROWINGS

SHORT-TERM DEBT

The following table presents the status of the Company's lines of credit as of December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2008	Restricted Due to Outstanding Letters of Credit	Available on December 31, 2008
Varistar Credit Agreement	$ 200,000	$ 107,849	$ 14,445	$ 77,706
Electric Utility Credit Agreement	170,000	27,065	—	142,935
Total	$ 370,000	$ 134,914	$ 14,445	$ 220,641

The weighted average interest rates on consolidated short-term debt outstanding on December 31, 2008 and 2007 were 2.8%. and 6.3%, respectively. The weighted average interest rate paid on consolidated short-term debt was 4.1% in 2008 and 6.0% in 2007.

On December 23, 2008 the Company's wholly owned subsidiary, Varistar Corporation (Varistar), entered into a $200 million Amended and Restated Credit Agreement (the Varistar Credit Agreement) with the Banks named therein, U.S. Bank National Association, a national banking 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. The Varistar Credit Agreement amends and restates the $200 million Credit Agreement, dated as of October 2, 2007 (the Original Credit Agreement), among the parties to the Varistar Credit Agreement, and is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Original Credit Agreement was amended to provide that, in the event the Company elects to form a holding company, the Varistar Credit Agreement will become an obligation of the new holding company on the terms and subject to the conditions specified in the Varistar Credit Agreement, which include changes to the interest rate and financial covenants. The line of credit may be increased to $300 million on the terms and subject to the conditions described in the Varistar Credit Agreement and will expire on October 2, 2010. On effectiveness of the amendment, borrowings under the line of credit bear interest at LIBOR plus 2.0%, subject to adjustment based on Varistar's adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). In the event the Company elects to form a holding company on the terms and subject to the conditions specified in the Varistar Credit Agreement (the Permitted Reorganization), the interest rate for loans after the effectiveness of the Permitted Reorganization will be based on the senior unsecured credit ratings of the new holding company.

The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Varistar Credit Agreement also contains affirmative covenants and events of default. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries.

On July 30, 2008 Otter Tail Corporation, dba Otter Tail Power Company replaced its credit agreement with U.S. Bank National Association, which provided for a $75 million line of credit, with a new credit agreement providing for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million as described in the new credit agreement. The new credit agreement (the Electric Utility Credit Agreement) is between Otter Tail Corporation, dba Otter Tail Power Company and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The Electric Utility Credit Agreement is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of the Company's senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement also contains affirmative covenants and events of default. The Electric Utility Credit Agreement is subject to renewal on July 30, 2011.

LONG-TERM DEBT

At closings completed in August 2007 and October 2007, the Company issued $155 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of the Company's 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of the Company's 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007 the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of the Company's senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 the Company issued the Cascade Note. The Cascade Note bears interest at a rate of 5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company's $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem the Company's $50 million 6.375% Senior Debentures due December 1, 2007. Cascade owned approximately 9.6% of the Company's outstanding common stock as of December 31, 2008.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states the Company must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on the businesses of the Company and its subsidiaries. In each case these include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Company's obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of its subsidiaries.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2008 for each of the next five years are $3,763,000 for 2009, $3,417,000 for 2010, $90,561,000 for 2011, $10,478,000 for 2012 and $68,000 for 2013.

FINANCIAL COVENANTS

The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, the Lombard US Equipment Finance Note and the financial guaranty insurance policy with Ambac Assurance Corporation relating to the Company's pollution control refunding bonds contain covenants by the Company to not permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, its interest coverage ratio) to be less than 1.5 to 1. On effectiveness of the Permitted Reorganization, the Varistar Credit Agreement will contain similar covenants applicable to the new holding company. The note purchase agreements further restrict the Company from allowing its priority debt to exceed 20% of total capitalization. The Varistar Credit Agreement also contains certain financial covenants that will apply to Varistar until the effectiveness of the Permitted Reorganization. Specifically, Varistar must maintain a fixed charge coverage ratio (as defined in the Varistar Credit Agreement) of not less than 1.20 to 1.00 for each period of four consecutive fiscal quarters through March 31, 2009, and not less than 1.25 to 1.00 for each period of four consecutive fiscal quarters ending June 30, 2009 and thereafter. In addition, Varistar must not permit its cash flow leverage ratio (as defined in the Varistar Credit Agreement) to exceed 3.25 to 1.00 for each period of four consecutive fiscal quarters through March 31, 2009, or to exceed 3.00 to 1.00 for each period of four consecutive fiscal quarters ending June 30, 2009 and thereafter. The Company's Credit and Note Purchase Agreements do not contain provisions that would trigger an acceleration of the Company's debt caused by credit rating levels assigned to the Company by rating agencies. The Company and Varistar each were in compliance with all of the financial covenants under their respective financing agreements as of December 31, 2008.

11. CLASS B STOCK OPTIONS OF SUBSIDIARY

In connection with the acquisition of IPH in August 2004, IPH management and certain other employees elected to retain stock options for the purchase of IPH Class B common shares valued at $1.8 million. The options are exercisable at any time and the option holder must deliver cash to exercise the option. Once the options are exercised for Class B shares, the Class B shareholder cannot put the shares back to the Company for 181 days. At that time, the Class B common shares are redeemable at any time during the employment of the individual holder, subject to certain limits on the total number of Class B common shares redeemable on an annual basis. The Class B common shares are nonvoting, except in the event of a merger, and do not participate in dividends but have liquidation rights at par with the Class A common shares owned by the Company. The value of the Class B common shares issued on exercise of the options represents an interest in IPH that changes as defined in the agreement. In 2008, 21 options were forfeited as a result of a voluntary termination. As of December 31, 2008 there were 912 options outstanding with a combined exercise price of $683,000, of which 732 options were "in-the-money" with a combined exercise price of $307,000.

12. PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The following footnote reflects the adoption of SFAS No. 158, *Accounting for Defined Benefit Pension and Other Postretirement Plans*, in December 2006. The Company determined that the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Losses in equity as prescribed by SFAS No. 158.

PENSION PLAN

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

The pension plan has a trustee who is responsible for pension payments to retirees. Five investment managers are responsible for managing the plan's assets. An independent actuary assists the Company in performing the necessary actuarial valuations for the plan.

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

Components of net periodic pension benefit cost:

(in thousands)	2008	2007	2006
Service Cost—Benefit Earned During the Period	**$ 4,630**	$ 4,837	$ 5,057
Interest Cost on Projected Benefit Obligation	**11,325**	10,790	10,435
Expected Return on Assets	**(13,968)**	(12,948)	(12,288)
Amortization of Prior-Service Cost	**742**	742	742
Amortization of Net Actuarial Loss	**169**	1,091	1,844
Net Periodic Pension Cost	**$ 2,898**	$ 4,512	$ 5,790

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

	2008	2007	2006
Discount Rate	6.25%	6.00%	5.75%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%	3.75%

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

(in thousands)	2008	2007
Regulatory Assets:		
Unrecognized Prior Service Cost	**$ 3,303**	$ 4,018
Unrecognized Actuarial Loss	**56,652**	17,115
Total Regulatory Assets	**59,955**	21,133
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	**(55)**	(72)
Unrecognized Actuarial Loss	**(943)**	(307)
Total Accumulated Other Comprehensive Loss	**(998)**	(379)
Deferred Income Taxes	**(666)**	(252)
Prepaid Pension Cost	**6,595**	7,493
Net Amount Recognized—Noncurrent Liability	**$ (55,024)**	$ (14,271)

Funded status as of December 31:

(in thousands)	2008	2007
Accumulated Benefit Obligation	**$ (153,676)**	$ (154,373)
Projected Benefit Obligation	**$ (182,559)**	$ (185,206)
Fair Value of Plan Assets	**127,535**	170,935
Funded Status	**$ (55,024)**	$ (14,271)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations and prepaid pension cost over the two-year period ended December 31, 2008:

(in thousands)	2008	2007
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	**$ 170,935**	$ 167,508
Actual Return on Plan Assets	**(36,523)**	8,013
Discretionary Company Contributions	**2,000**	4,000
Benefit Payments	**(8,877)**	(8,586)
Fair Value of Plan Assets at December 31	**$ 127,535**	$ 170,935
Estimated Asset Return	**(21.94)%**	4.85%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	**$ 185,206**	$ 186,760
Service Cost	**4,630**	4,837
Interest Cost	**11,325**	10,790
Benefit Payments	**(8,877)**	(8,586)
Actuarial Gain	**(9,725)**	(8,595)
Projected Benefit Obligation at December 31	**$ 182,559**	$ 185,206
Reconciliation of Prepaid Pension Cost:		
Prepaid Pension Cost at January 1	**$ 7,493**	$ 8,005
Net Periodic Pension Cost	**(2,898)**	(4,512)
Discretionary Company Contributions	**2,000**	4,000
Prepaid Pension Cost at December 31	**$ 6,595**	$ 7,493

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

	2008	2007
Discount Rate	6.70%	6.25%
Rate of Increase in Future Compensation Level	3.75%	3.75%

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

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

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

The assumed rate of return on pension fund assets for the determination of 2009 net periodic pension cost is 8.50%.

Measurement Dates:	2008	2007
Net Periodic Pension Cost	**January 1, 2008**	January 1, 2007
End of Year Benefit Obligations	**January 1, 2008 projected to December 31, 2008**	January 1, 2007 projected to December 31, 2007
Market Value of Assets	**December 31, 2008**	December 31, 2007

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2009 are:

(in thousands)	2009
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 704
Amortization of Unrecognized Actuarial Loss	21
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	20
Amortization of Unrecognized Actuarial Loss	1
Total Estimated Amortization	$ 746

Cash flows—The Company is not required to make a contribution to the pension plan in 2009.

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

(in thousands)		Years			
2009	2010	2011	2012	2013	2014-2018
$ 9,123	$ 9,286	$ 9,390	$ 9,766	$ 10,139	$ 59,081

The Company's pension plan asset allocations at December 31, 2008 and 2007, by asset category are as follows:

Asset Allocation	2008	2007
Large Capitalization Equity Securities	**39.6%**	47.1%
Small Capitalization Equity Securities	**9.2%**	10.7%
International Equity Securities	**8.3%**	10.4%
Total Equity Securities	**57.1%**	68.2%
Cash and Fixed-Income Securities	**42.9%**	31.8%
	100.0%	100.0%

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

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

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

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

The Company's Retirement Plans Administrative Committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining current targeted allocation percentages listed in the table below.

Asset Allocation	Strategic Target	Tactical Range
Large Capitalization Equity Securities	48%	40%–55%
Small Capitalization Equity Securities	12%	9%–15%
International Equity Securities	10%	5%–15%
Total Equity Securities	70%	60%–80%
Fixed-Income Securities	30%	20%–40%

EXECUTIVE SURVIVOR AND SUPPLEMENTAL RETIREMENT PLAN (ESSRP)

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

Components of net periodic pension benefit cost:

(in thousands)	2008	2007	2006
Service Cost—Benefit Earned During the Period	**$ 691**	$ 626	$ 426
Interest Cost on Projected Benefit Obligation	**1,535**	1,451	1,303
Amortization of Prior-Service Cost	**66**	67	71
Amortization of Net Actuarial Loss	**480**	540	473
Net Periodic Pension Cost	**$ 2,772**	$ 2,684	$ 2,273

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

	2008	2007	2006
Discount Rate	**6.25%**	6.00%	5.75%
Rate of Increase in Future Compensation Level	**4.70%**	4.71%	4.69%

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

(in thousands)	2008	2007
Regulatory Assets:		
Unrecognized Prior Service Cost	**$ 421**	$ 435
Unrecognized Actuarial Loss	**4,114**	4,841
Total Regulatory Assets	**4,535**	5,276
Projected Benefit Obligation Liability—Net Amount Recognized	**(25,888)**	(25,158)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	**(166)**	(160)
Unrecognized Actuarial Loss	**(1,626)**	(1,772)
Total Accumulated Other Comprehensive Loss	**(1,792)**	(1,932)
Deferred Income Taxes	**(1,194)**	(1,288)
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	**$ (18,367)**	$ (16,662)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2008 and a statement of the funded status as of December 31 of both years:

(in thousands)	2008	2007
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Employer Contributions	1,067	1,079
Benefit Payments	(1,067)	(1,079)
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 25,158	$ 24,783
Service Cost	691	626
Interest Cost	1,535	1,451
Benefit Payments	(1,067)	(1,079)
Plan Amendments	63	—
Actuarial Gain	(492)	(623)
Projected Benefit Obligation at December 31	$ 25,888	$ 25,158
Reconciliation of Funded Status:		
Funded Status at December 31	$ (25,888)	$ (25,158)
Unrecognized Net Actuarial Loss	6,823	7,795
Unrecognized Prior Service Cost	698	701
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (18,367)	$ (16,662)

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

	2008	2007
Discount Rate	6.70%	6.25%
Rate of Increase in Future Compensation Level	4.70%	4.70%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2009 are:

(in thousands)	2009
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 43
Amortization of Unrecognized Actuarial Loss	232
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	28
Amortization of Unrecognized Actuarial Loss	153
Total Estimated Amortization	$ 456

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

(in thousands)		Years			
2009	2010	2011	2012	2013	2014-2018
$ 1,114	$ 1,117	$ 1,228	$ 1,288	$ 1,274	$ 7,220

OTHER POSTRETIREMENT BENEFITS

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

Components of net periodic postretirement benefit cost:

(in thousands)	2008	2007	2006
Service Cost—Benefit Earned During the Period	$ 1,103	$ 1,098	$ 1,319
Interest Cost on Projected Benefit Obligation	2,689	2,565	2,556
Amortization of Transition Obligation	748	748	748
Amortization of Prior-Service Cost	211	(206)	(305)
Amortization of Net Actuarial Loss	26	177	556
Expense Decrease Due to Medicare Part D Subsidy	(1,172)	(1,233)	(1,543)
Net Periodic Postretirement Benefit Cost	$ 3,605	$ 3,149	$ 3,331

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

	2008	2007	2006
Discount Rate	6.25%	6.00%	5.75%

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

(in thousands)	2008	2007
Regulatory Asset:		
Unrecognized Transition Obligation	$ 1,454	$ 3,658
Unrecognized Prior Service Cost	1,567	1,781
Unrecognized Net Actuarial Gain	(3,855)	(4,915)
Net Regulatory (Liability) Asset	(834)	524
Projected Benefit Obligation Liability—Net Amount Recognized	(32,621)	(30,488)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	(923)	(50)
Unrecognized Prior Service Cost	(26)	(24)
Unrecognized Net Actuarial Gain	64	67
Accumulated Other Comprehensive Loss	(885)	(7)
Deferred Income Taxes	(590)	(5)
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (31,980)	$ (29,952)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2008:

(in thousands)	2008	2007
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Company Contributions	1,577	1,459
Benefit Payments (Net of Medicare Part D Subsidy)	(3,392)	(3,127)
Participant Premium Payments	1,815	1,668
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 30,488	$ 32,254
Service Cost (Net of Medicare Part D Subsidy)	902	890
Interest Cost (Net of Medicare Part D Subsidy)	1,874	1,776
Benefit Payments (Net of Medicare Part D Subsidy)	(3,392)	(3,127)
Participant Premium Payments	1,815	1,668
Actuarial Loss (Gain)	934	(2,973)
Projected Benefit Obligation at December 31	$ 32,621	$ 30,488
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (29,952)	$ (28,262)
Expense	(3,605)	(3,149)
Net Company Contribution	1,577	1,459
Accrued Postretirement Cost at December 31	$ (31,980)	$ (29,952)

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

	2008	2007
Discount Rate	6.70%	6.25%

Assumed healthcare cost-trend rates as of December 31:

	2008	2007
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	7.40%	8.00%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	8.00%	9.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2017	2012

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2008 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 3,052	$ (2,644)
Effect on Total of Service and Interest Cost	$ 362	$ (298)
Effect on Expense	$ 492	$ (554)

Measurement Dates:	2008	2007
Net Periodic Postretirement Benefit Cost	January 1, 2008	January 1, 2007
End of Year Benefit Obligations	January 1, 2008 projected to December 31, 2008	January 1, 2007 projected to December 31, 2007

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2009 are:

(in thousands)	2009
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 364
Amortization of Unrecognized Prior Service Cost	204
Amortization of Unrecognized Actuarial Gain	(71)
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	384
Amortization of Unrecognized Prior Service Cost	6
Amortization of Unrecognized Actuarial Gain	(2)
Total Estimated Amortization	$ 885

Cash flows—The Company expects to contribute $2.4 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2009. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $447,000 in 2009. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands) **Years**

2009	2010	2011	2012	2013	2014–2018
$ 2,371	$ 2,327	$ 2,468	$ 2,568	$ 2,696	$ 15,163

LEVERAGED EMPLOYEE STOCK OWNERSHIP PLAN

The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $738,000 for 2008, $733,000 for 2007 and $738,000 for 2006.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

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

	December 31, 2008		December 31, 2007	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 7,565	$ 7,565	$ 39,824	$ 39,824
Long-Term Debt	(339,726)	(308,283)	(342,694)	(354,242)

14. PROPERTY, PLANT AND EQUIPMENT

(in thousands)	December 31, 2008	December 31, 2007
Electric Plant		
Production	$ 590,252	$ 439,541
Transmission	201,456	191,949
Distribution	337,296	322,107
General	76,643	75,320
Electric Plant	1,205,647	1,028,917
Less Accumulated Depreciation and Amortization	421,177	401,006
Electric Plant Net of Accumulated Depreciation	784,470	627,911
Construction Work in Progress	25,547	33,772
Net Electric Plant	$ 810,017	$ 661,683
Nonelectric Operations Plant		
Equipment	$ 220,985	$ 181,743
Buildings and Leasehold Improvements	80,281	62,563
Land	19,766	13,284
Nonelectric Operations Plant	321,032	257,590
Less Accumulated Depreciation and Amortization	126,893	105,738
Nonelectric Plant Net of Accumulated Depreciation	194,139	151,852
Construction Work in Progress	33,413	40,489
Net Nonelectric Operations Plant	$ 227,552	$ 192,341
Net Plant	$ 1,037,569	$ 854,024

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

(years)	Service Life Range Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65
Nonelectric Fixed Assets:		
Equipment	3	12
Buildings and Leasehold Improvements	7	40

15. INCOME TAXES

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2008, 2007 and 2006) to net income before total income tax expense for the following reasons:

(in thousands)	2008	2007	2006
Tax Computed at Federal Statutory Rate	$ 17,556	$ 28,675	$ 27,232
Increases (Decreases) in Tax from:			
State Income Taxes Net of Federal Income Tax Benefit	2,806	2,945	2,261
Differences Reversing in Excess of Federal Rates	1,089	929	1,271
Federal Production Tax Credit	(3,234)	(3)	—
Investment Tax Credit Amortization	(1,125)	(1,137)	(1,146)
Dividend Received/Paid Deduction	(718)	(714)	(718)
North Dakota Wind Tax Credit Amortization	(567)	(32)	—
Affordable Housing Tax Credits	(55)	(285)	(839)
Section 199 Domestic Production Activities Deduction	—	(1,159)	(524)
Permanent and Other Differences	(715)	(1,251)	(431)
Total Income Tax Expense	$ 15,037	$ 27,968	$ 27,106
Income Tax Expense—Discontinued Operations	$ —	$ —	$ 252
Overall Effective Federal and State Income Tax Rate	30.0%	34.1%	34.9%
Income Tax Expense Includes the Following:			
Current Federal Income Taxes	$ (19,813)	$ 23,210	$ 26,276
Current State Income Taxes	(1,115)	2,371	4,232
Deferred Federal Income Taxes	39,051	2,832	(937)
Deferred State Income Taxes	5,280	2,116	(189)
Foreign Income Taxes	(3,385)	(1,104)	(291)
Federal Production Tax Credit	(3,234)	(3)	—
Investment Tax Credit Amortization	(1,125)	(1,137)	(1,146)
North Dakota Wind Tax Credit Amortization	(567)	(32)	—
Affordable Housing Tax Credits	(55)	(285)	(839)
Total	$ 15,037	$ 27,968	$ 27,106

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

(in thousands)	2008	2007
Deferred Tax Assets		
Related to North Dakota Wind Tax Credits	$ 35,902	$ 12,999
Benefit Liabilities	32,932	30,789
Cost of Removal	22,920	22,537
Differences Related to Property	10,300	8,703
SFAS No. 158 Liabilities	9,650	10,504
Net Operating Loss Carryforward	6,379	1,815
Amortization of Tax Credits	4,946	4,505
Vacation Accrual	3,003	2,926
Unearned Revenue	1,829	1,733
Other	3,790	2,248
Total Deferred Tax Assets	$ 131,651	$ 98,759
Deferred Tax Liabilities		
Differences Related to Property	$ (212,419)	$ (166,445)
Related to North Dakota Wind Tax Credits	(10,074)	(4,340)
SFAS No. 158 Regulatory Asset	(9,650)	(10,504)
Transfer to Regulatory Asset	(7,093)	(8,732)
Excess Tax over Book Pension	(2,599)	(2,953)
Other	(4,516)	(4,398)
Total Deferred Tax Liabilities	$ (246,351)	$ (197,372)
Deferred Income Taxes	$ (114,700)	$ (98,613)

On January 1, 2007 the Company adopted the provisions of FIN No. 48. The cumulative effect of adoption of FIN No. 48, which is reported as an adjustment to the beginning balance of retained earnings, was $118,000. As of the date of adoption, the total amount of unrecognized tax benefits for uncertain tax positions was $1,874,000. The amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate was $575,000 as of January 1, 2007.

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

(in thousands)	Total
Balance at January 1, 2008	$ 506
Increases Related to Current Year Tax Positions	—
Expiration of the Statute of Limitations for the Assessment of Taxes	(222)
Balance at December 31, 2008	$ 284

The balance of unrecognized tax benefits as of December 31, 2008 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2008 is not expected to change significantly within the next 12 months. The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2008 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2005. As of December 31, 2008 the Company's earliest open tax year in which an audit can be initiated by state taxing authorities in the Company's major operating jurisdictions is 2004 for Minnesota and 2005 for North Dakota. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2008 were not material.

16. ASSET RETIREMENT OBLIGATIONS (AROS)

The Company's AROs are related to coal-fired generation plants, 27 wind turbines located near Langdon, North Dakota and 32 wind turbines at the Ashtabula Wind Energy Center in North Dakota and include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

During 2008, the electric utility recorded new obligations related to the removal of 32 wind turbines located at the Ashtabula Wind Energy Center in Barnes County, North Dakota and restoration of the tower sites and made revisions to previously recorded obligations related to site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos at its coal-fired generation plants.

The measurements used to determine the fair values of electric utility's AROs fall into level 3, of the fair value hierarchy set forth in SFAS No. 157, *Fair Value Measurements*. The electric utility determined the fair value of its future obligations related to the removal of 32 wind turbines located at the Ashtabula Wind Energy Center by engaging an outside engineering firm with expertise in demolition and removal to provide an estimate of the current costs to remove these assets, then projected the costs forward to 2033 using an inflation rate of 3.1% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 9.0%.

During 2007, the Company recorded new obligations related to the removal of 27 wind turbines located near Langdon, North Dakota and restoration of the tower sites but did not make any revisions to previously recorded obligations.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2008 and 2007 are presented in the following table:

(in thousands)	2008	2007
Asset Retirement Obligations		
Beginning Balance	$ 2,447	$ 1,335
New Obligations Recognized	317	1,024
Adjustments Due to Revisions in Cash Flow Estimates	407	—
Accrued Accretion	127	88
Settlements	—	—
Ending Balance	$ 3,298	$ 2,447
Asset Retirement Costs Capitalized		
Beginning Balance	$ 1,309	$ 285
New Obligations Recognized	317	1,024
Adjustments Due to Revisions in Cash Flow Estimates	(565)	—
Settlements	—	—
Ending Balance	$ 1,061	$ 1,309
Accumulated Depreciation—Asset Retirement Costs Capitalized		
Beginning Balance	$ 185	$ 178
New Obligations Recognized	—	—
Adjustments Due to Revisions in Cash Flow Estimates	(34)	—
Accrued Depreciation	28	7
Settlements	—	—
Ending Balance	$ 179	$ 185
Settlements		
Original Capitalized Asset Retirement Cost-Retired	$ —	$ —
Accumulated Depreciation	—	—
Asset Retirement Obligation	$ —	$ —
Settlement Cost	—	—
Gain on Settlement—Deferred Under Regulatory Accounting	$ —	$ —

17. QUARTERLY INFORMATION (NOT AUDITED)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings per common share may not equal total earnings per common share.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Operating Revenues	**$ 300,237**	$ 301,121	**$ 323,600**	$ 305,844	**$ 352,919**	$ 302,235	**$ 334,441**	$ 329,687
Operating Income	**17,097**	20,774	**10,303**	30,271	**19,746**	25,547	**25,846**	24,182
Net Income	**8,230**	10,408	**3,517**	16,103	**9,631**	13,332	**13,747**	14,118
Earnings Available for Common Shares	**8,046**	10,224	**3,333**	15,919	**9,447**	13,148	**13,563**	13,934
Basic Earnings Per Share	**$ .27**	$ .35	**$ .11**	$ .54	**$ .31**	$ .44	**$ .38**	$ .47
Diluted Earnings Per Share:	**$ .27**	$ .34	**$ .11**	$ .53	**$ .31**	$ .44	**$ .38**	$ .46
Dividends Paid Per Common Share	**$ .2975**	$ .2925	**$ .2975**	$ .2925	**$ .2975**	$ .2925	**$ .2975**	$ .2925
Price Range:								
High	**35.68**	35.00	**40.98**	37.06	**46.15**	39.39	**30.84**	37.88
Low	**31.28**	31.06	**34.93**	30.22	**29.71**	28.96	**14.99**	32.82
Average Number of Common Shares Outstanding—Basic	**29,816**	29,503	**29,993**	29,686	**30,514**	29,746	**35,311**	29,790
Average Number of Common Shares Outstanding—Diluted	**30,062**	29,757	**30,300**	29,941	**30,817**	29,996	**35,516**	30,090

CONSOLIDATED STATISTICAL SUPPLEMENT

OPERATING RATIOS

(in thousands)	2008	2007	2006	2005	2004	2003	1998
Operating Revenues	$ 1,311,197	$1,238,887	$1,104,954	$ 981,869	$ 813,036	$ 688,989	$ 391,077
Operating Expenses (a)	$ 1,238,205	$1,138,113	$1,007,157	$ 883,274	$ 737,828	$ 620,026	$ 336,030
Operating Ratio	94.4	91.9	91.1	90.0	90.7	90.0	85.9

SELECTED COMMON SHARE DATA

(in thousands)	2008	2007	2006	2005	2004	2003	1998
Earnings Available for Common Shares	$ 34,389	$ 53,225	$ 50,376	$ 61,816	$ 41,459	$ 38,921	$ 32,162
Average Number of Shares—Diluted	31,673	29,970	29,664	29,348	26,207	25,826	23,596
Diluted Earnings Per Share	$ 1.09	$ 1.78	$ 1.70	$ 2.11	$ 1.58	$ 1.51	$ 1.36
Common Dividends	$ 37,357	$ 34,780	$ 33,886	$ 32,728	$ 28,528	$ 27,730	$ 22,642
Dividends Paid Per Share	$ 1.19	$ 1.17	$ 1.15	$ 1.12	$ 1.10	$ 1.08	$ 0.96
Payout Ratio	109%	66%	68%	53%	70%	72%	71%
Market Price:							
High	$ 46.15	$ 39.39	$ 31.92	$ 31.95	$ 27.50	$ 28.90	$ 21.38
Low	$ 14.99	$ 28.96	$ 25.78	$ 24.02	$ 23.77	$ 23.76	$ 15.06
Common Price/Earnings Ratio:							
High	42.3	22.1	18.8	15.1	17.4	19.1	15.7
Low	13.8	16.3	15.2	11.4	15.0	15.7	11.1
Book Value Per Common Share	$ 19.10	$ 17.51	$ 16.62	$ 15.80	$ 14.81	$ 12.98	$ 9.47

SELECTED DATA AND RATIOS

	2008	2007	2006	2005	2004	2003	1998
Net Income (in thousands)	$ 35,125	$ 53,961	$ 51,112	$ 62,551	$ 42,195	$ 39,656	$ 34,520
Interest Coverage Before Taxes	2.8x	4.7x	5.2x	5.7x	4.4x	4.1x	4.1x
Effective Income Tax Rate (percent)	30	34	35	34	30	27	32
Capital Ratios:							
Long-Term Debt and Current Maturities (percent)	33.2	39.1	33.7	35.2	37.5	43.6	40.1
Preferred Stock and Other Equity (percent)	1.6	1.9	2.2	2.3	2.4	2.5	8.8
Common Equity (percent)	65.2	59.0	64.1	62.5	60.1	53.9	51.1
	100.0	100.0	100.0	100.0	100.0	100.0	100.0

CAPITALIZATION

(in thousands)	2008	2007	2006	2005	2004	2003	1998
Long-Term Debt and Current Maturities	$ 343,473	$ 345,698	$ 258,561	$ 261,600	$ 267,821	$ 270,597	$ 176,448
Preferred Stock and Other Equity	16,720	16,755	16,755	16,758	17,332	15,500	38,831
Common Stock Equity:							
Par	176,923	149,249	147,609	147,006	144,885	128,619	59,398
Premium	241,731	108,885	99,223	96,768	87,865	26,515	39,919
Unearned Compensation	—	—	—	(1,720)	(2,577)	(3,313)	—
Retained Earnings and Other Comprehensive Income (Loss)	257,364	264,513	243,938	222,376	199,037	182,066	125,759
Total Common Equity	$ 676,018	$ 522,647	$ 490,770	$ 464,430	$ 429,210	$ 333,887	$ 225,076
Total Capitalization Including Current Maturities	$ 1,036,211	$ 885,100	$ 766,086	$ 742,788	$ 714,363	$ 619,984	$ 440,355
Income Before Interest Charges (includes AFC borrowed)	$ 64,240	$ 77,483	$ 70,484	$ 72,551	$ 58,863	$ 56,535	$ 43,969
Percent Return on Capitalization	6.2	8.8	9.2	9.8	8.2	9.1	10.0
Percent Return on Average Common Equity	6.0	10.5	10.6	13.9	12.0	12.2	15.0

TIMES INTEREST EARNED AND PREFERRED DIVIDEND COVERAGE (a)

	2008	2007	2006	2005	2004	2003	1998
Before Income Taxes:							
Long-Term Debt Interest (b)	3.8	6.2	6.2	6.4	4.9	4.3	4.3
After Income Taxes:							
Long-Term Debt Interest (c)	3.1	4.6	4.5	4.6	3.8	3.4	3.3
Long-Term Debt Interest and Preferred Dividends (d)	3.0	4.4	4.3	4.4	3.6	3.3	2.8
Preferred Dividends (e)	47.7	73.3	69.0	73.3	55.0	52.1	12.4

(a) Excludes income taxes
(b) Income before interest charges + income taxes ÷ long-term debt interest
(c) Income before interest charges ÷ long-term debt interest
(d) Income before interest charges ÷ long-term debt interest and preferred dividends
(e) Net income ÷ preferred dividends

ELECTRIC UTILITY STATISTICAL SUPPLEMENT

DEPRECIATION RESERVE

(in thousands)	**2008**	2007	2006	2005	2004	2003	1998
Electric Plant in Service	**$ 1,205,647**	$1,028,917	$ 930,689	$ 910,766	$ 890,200	$ 875,364	$ 770,887
Depreciation Reserve	**$ 421,177**	$ 401,006	$ 388,254	$ 374,786	$ 363,696	$ 368,899	$ 297,738
Reserve to Electric Plant (percent)	**34.9**	39.0	41.7	41.2	40.9	42.1	38.6
Composite Depreciation Rate (percent)	**2.81**	2.78	2.82	2.74	2.77	3.07	3.12

RATIO OF DEBT TO ELECTRIC PLANT

(in thousands)	**2008**	2007	2006	2005	2004	2003	1998
Electric Plant:							
Gross (a)	**$ 1,231,194**	$1,062,689	$ 949,192	$ 923,215	$ 902,412	$ 889,302	$ 781,382
Net	**$ 810,017**	$ 661,683	$ 560,938	$ 548,429	$ 538,716	$ 520,403	$ 483,644
Debt (b)	**$ 256,790**	$ 199,890	$ 166,975	$ 166,975	$ 166,975	$ 166,975	$ 154,384
Ratio to Electric Plant—Net (a) (percent)	**32**	30	30	30	31	32	32

PEAK DEMAND AND NET GENERATING CAPABILITY

	2008	2007	2006	2005	2004	2003	1998
Peak Demand (kw)	**765,000**	704,940	690,243	665,064	686,044	668,703	635,174
Net Generating Capability (kw):							
Steam	**549,925**	549,800	549,350	559,175	554,330	555,085	556,851
Combustion Turbines	**131,045**	132,744	137,595	135,701	136,506	136,915	90,634
Hydro	**3,742**	4,338	4,294	4,244	4,327	4,380	4,109
Wind	**41,383**	—	—	—	—	—	—
Total Owned Generating Capability	**726,095**	686,882	691,239	699,120	695,163	696,380	651,594

ELECTRIC INVESTMENT

	2008	2007	2006	2005	2004	2003	1998
Electric Utility Plant—Net (c) (in thousands)	**$ 810,017**	$ 661,683	$ 560,938	$ 548,429	$ 538,716	$ 520,403	$ 483,644
Total Retail Electric Revenue (in thousands)	**$ 287,631**	$ 276,894	$ 260,926	$ 248,939	$ 224,326	$ 217,439	$ 187,279
Total Retail Electric Customers	**129,239**	129,302	129,026	128,406	128,157	127,474	125,655
Investment Per Dollar Revenue	**$ 2.82**	$ 2.39	$ 2.15	$ 2.20	$ 2.40	$ 2.39	$ 2.58
Investment Per Customer	**$ 6,268**	$ 5,117	$ 4,347	$ 4,271	$ 4,204	$ 4,082	$ 3,849

OUTPUT KILOWATT-HOURS

(in thousands)	**2008**	2007	2006	2005	2004	2003	1998
Net Generated	**3,856,095**	3,386,041	3,571,410	3,513,705	3,774,115	3,672,616	3,202,143
Purchased, Net Interchange and Financial Settlements	**3,112,989**	2,465,598	3,218,537	3,495,176	4,910,428	5,898,456	2,446,034
Total	**6,969,084**	5,851,639	6,789,947	7,008,881	8,684,543	9,571,072	5,648,177

(a) Includes construction work in progress
(b) Includes sinking fund requirements and current maturities
(c) Electric plant in service less accumulated provision for depreciation plus construction work in progress

SHAREHOLDER SERVICES

OTTER TAIL CORPORATION STOCK LISTING

Otter Tail Corporation common stock trades on the NASDAQ Global Select Market. The daily closing price is printed in *The Wall Street Journal*, Minneapolis *Star Tribune*, *The Forum* of Fargo-Moorhead and other major daily newspapers. Our ticker symbol is OTTR. You also can find our daily stock price on our web site, www.ottertail.com. Shareholders who sign up for Internet account access can view their account information online.

DIVIDENDS

Otter Tail Corporation has paid dividends on our common shares each quarter since 1938 without interruption or reduction. 2008 dividends were $1.19 per share and the yield was 5.1%. Total shareholder return grew at a compounded average annual rate of 5.8% for the past 10 years.

DIVIDEND REINVESTMENT

The corporation's Dividend Reinvestment and Share Purchase Plan provides shareholders of record with a convenient method for purchasing shares of Otter Tail Corporation common stock. About 78% of eligible shareowners holding about 12% of our eligible common shares are enrolled. Through this plan, participants may have their dividends automatically reinvested in additional shares without paying any brokerage fees or service charges. Shareholders also may contribute a minimum of $10 and a maximum of $10,000 per month. Automatic withdrawal from a checking or savings account is available for this service. Shareholders may sell up to 30 shares a month through the plan. For more information, contact Shareholder Services.

ELECTRONIC DIVIDEND DEPOSIT

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

PROTECTING STOCK CERTIFICATES

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

TRANSFER AGENTS

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

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

2009 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 20, 2009
10:00 a.m., Central Time
Bigwood Event Center
921 Western Avenue
Fergus Falls, Minnesota

EX-DIVIDEND	RECORD	PAYMENT	
Feb. 11	Feb. 13	P Feb. 28	C Mar. 10
May 13	May 15	P June 1	C June 10
Aug. 12	Aug. 14	P Sept. 1	C Sept. 10
Nov. 11	Nov. 13	P Dec. 1	C Dec. 10

KEY STATISTICS

NASDAQ	OTTR
Senior unsecured debt ratings	
Moody's Investor Service	A3/negative
Standard & Poor's	BBB-/stable
Year-end stock price	$23.33
Year-end price/earnings ratio	21.4
Year-end market-to-book ratio	1.2
Annual dividend yield	5.1%
Shares outstanding	35.4 million
Market capitalization (as of December 31, 2008)	$826 million
2008 average daily trading volume	251,478
Institutional holdings (shares as of December 31, 2008)	17.4 million

2009 CASH INVESTMENT AND SELL DATES FOR DIVIDEND REINVESTMENT

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

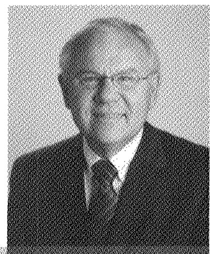
DIRECTORS

*(Age-years of service) are as of the 2009 Annual Meeting of Shareholders.
Committees: A-Audit C-Compensation E-Executive CG-Corporate Governance


John MacFarlane

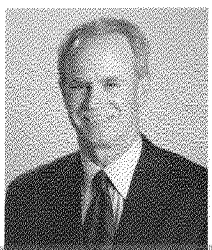

Karen Bohn

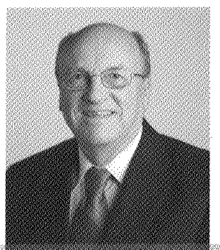

John Erickson

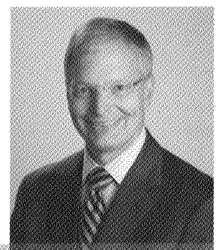

Arvid Liebe


Edward McIntyre


Joyce Schuette


Nathan Partain


Gary Spies


James Stake

JOHN C. MACFARLANE (69-26)* E, *Fergus Falls, Minnesota*
Chairman of the Board of Directors, Retired President and Chief Executive Officer, Otter Tail Corporation

KAREN M. BOHN (55-5) A/CG/E, *Edina, Minnesota*
President, Galeo Group, LLC (management consulting firm)

JOHN D. ERICKSON (50-2), *Fergus Falls, Minnesota*
President and Chief Executive Officer, Otter Tail Corporation

ARVID R. LIEBE (67-14) C/CG/E, *Milbank, South Dakota*
Retired President, Liebe Drug, Inc. (retail business); Owner, Liebe Farms, Inc.

EDWARD J. MCINTYRE (58-3) A/C, *White Salmon, Washington*
Retired Vice President and Chief Financial Officer, Xcel Energy (energy company)

JOYCE NELSON SCHUETTE (58-3) C/CG, *Walker, Minnesota*
Retired Managing Director and Investment Banker, Piper Jaffray & Co. (financial services)

NATHAN I. PARTAIN (52-16) A/C/E, *Chicago, Illinois*
President and Chief Investment Officer, Duff & Phelps Investment Management Co.; President, Chief Executive Officer and Chief Investment Officer, DNP Select Income Fund, Inc. (closed-end utility income fund)

GARY J. SPIES (67-8) A/CG, *Fergus Falls, Minnesota*
Chairman, Service Food, Inc. (retail business); Vice President, Fergus Falls Development Company and Midwest Regional Development Company, LLC (land and housing development)

JAMES B. STAKE (56-1) A/C, *Edina, Minnesota*
Retired Executive Vice President, Enterprise Services, 3M Company (diversified manufacturing)

OFFICERS


Left to right: Lauris Molbert, Kevin Moug, John Erickson, George Koeck

JOHN D. ERICKSON (50-28)* President and Chief Executive Officer

LAURIS N. MOLBERT (51-14) Executive Vice President and Chief Operating Officer

KEVIN G. MOUG (49-12) Chief Financial Officer

GEORGE A. KOECK (56-9) General Counsel and Corporate Secretary

VICE PRESIDENTS


Left to right: Paul Wilson, Shane Waslaski, Michelle Kommer, Charles MacFarlane, Charles Hoge, Richard Nickel

CHARLES S. MACFARLANE (44-7)* Electric Platform

CHARLES R. HOGE (52-6) Manufacturing Platform

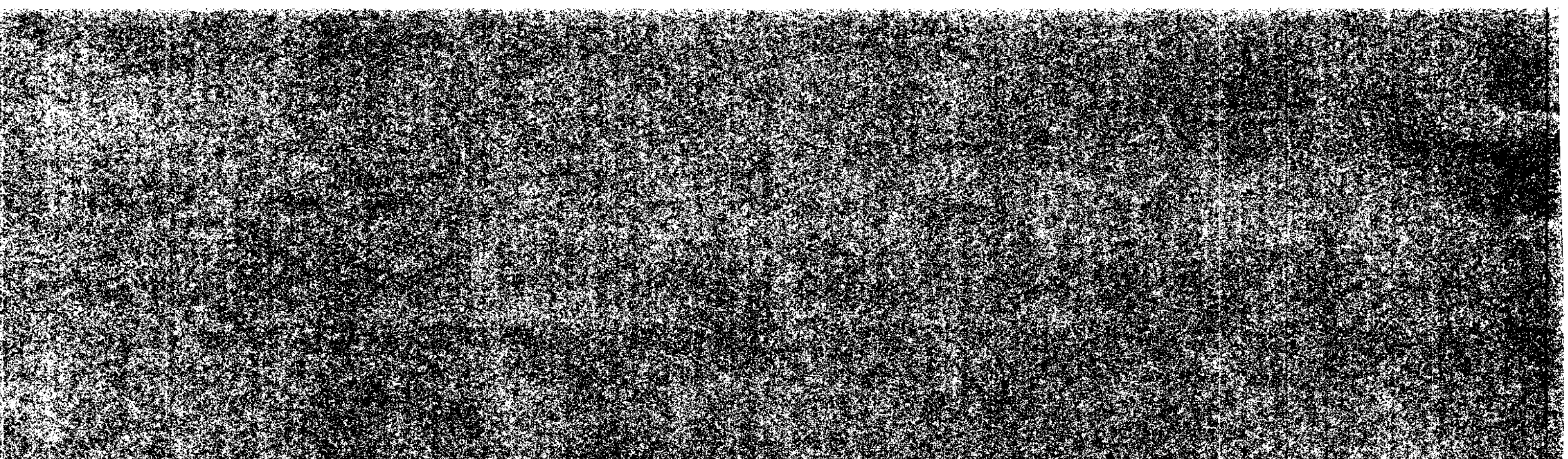
MICHELLE L. KOMMER (36-2) Corporate Human Resources

W. RICHARD NICKEL (66-4) Food Ingredient Processing Platform

SHANE N. WASLASKI (33-2) Infrastructure Products and Services Platform

PAUL J. WILSON (50-3) Health Services Platform

OTTERTAIL
CORPORATION



WWW.OTTERTAIL.COM **NASDAQ: OTTR**

SHAREHOLDER SERVICES
215 S. Cascade St., P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: 800-664-1259 or 218-739-8479
Email: sharesvc@ottertail.com