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DIVERSIFIED FOR GROWTH UNIFIED IN PURPOSE

OTTER TAIL CORPORATION

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MAR 1 2 2007

THOMSON FINANCIAL

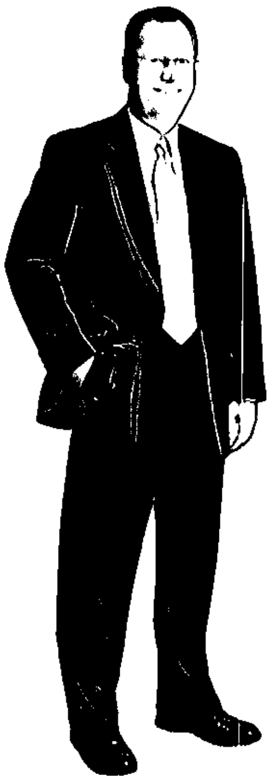
2006 ANNUAL REPORT

CONTENTS

HIGHLIGHTS OF THE YEAR

	2006	2005	PERCENT CHANGE
CONSOLIDATED OPERATIONS:			
Total operating revenues	$ 1,104,954,000	$ 981,869,000	12.5
Net income from continuing operations	50,750,000	53,902,000	(5.8)
Net income	51,112,000	62,551,000	(18.3)
Basic earnings per share	1.71	2.12	(19.3)
Diluted earnings per share from continuing operations	1.69	1.81	(6.6)
Diluted earnings per share	1.70	2.11	(19.4)
Dividends per common share	1.15	1.12	2.7
Return on average common equity	10.6%	13.9%	(23.7)
Book value per common share	16.62	15.80	5.2
Cash flow from continuing operations	79,207,000	90,348,000	(12.3)
Number of common shares outstanding	29,521,770	29,401,223	0.4
Number of common shareholders	14,692	14,801	(0.7)
Closing stock price	31.16	28.98	7.5
Total return (share price appreciation plus dividends)	11.5%	17.9%	(35.8)
Total market value of common stock	919,898,000	852,047,000	8.0
Total employees (all companies and corporate, includes temporary and part-time)	3,935	3,594	9.5
ELECTRIC OPERATIONS:			
Operating revenues:			
Retail	$ 260,926,000	$ 248,939,000	4.8
Wholesale—net of purchased power costs	25,965,000	46,397,000	(44.0)
Other	18,812,000	17,288,000	8.8
Total electric operating revenues	$ 305,703,000	$ 312,624,000	(2.2)
Total retail electric sales (kwh)	3,990,854,000	3,894,435,000	2.5
Operating income	50,111,000	63,886,000	(21.6)
Customers	129,070	128,466	0.5
Gross plant investment	949,191,000	923,215,000	2.8
Total assets	689,653,000	654,175,000	5.4
Capital expenditures	35,207,000	30,479,000	15.5
Employees (includes temporary and part-time)	700	692	1.2
NONELECTRIC OPERATIONS:			
Operating revenues	$ 799,251,000	$ 669,245,000	19.4
Operating income	47,686,000	34,709,000	37.4
Total assets	568,997,000	527,321,000	7.9
Capital expenditures	34,241,000	29,490,000	16.1
Employees (includes temporary and part-time)	3,181	2,859	11.3

ON THE COVER > Within Otter Tail Corporation, more than 3,900 people across our diverse businesses are working together to create growth and provide dependable value to shareholders. The 2006 annual report introduces six of these dedicated individuals. From left to right: SHARON WHISTLER, senior vice president at Foley Company; MIREYA MOLINA, plant sanitarian at Idaho Pacific; BRAD ZIMMERMAN, principal engineer at Otter Tail Power Company's Coyote Station; NEDZAD MUJIC, painter at DMI Industries; JILL WALDEN, line operator at Northern Pipe Products; and in front center, TOM KEMPER, service systems specialist at DMS Health Group.



JOHN ERICKSON
› President and CEO

› TO OUR SHAREHOLDERS

2006 was a good year for Otter Tail Corporation. Our results again show that diversification works and remains the right path to long-term growth and stability. Growth in our nonelectric businesses drove a record year in consolidated revenues, and we also produced solid results in net income. Our balance sheet, capital structure and cash flows all remained strong.

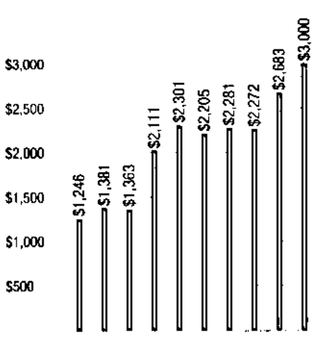
In all, I am pleased to report our 2006 outcomes as follows:

› Operating revenues increased to $1.1 billion.
› Net income was $51.1 million, with continuing operations producing $50.7 million of the total.
› Earnings per share were $1.70, with continuing operations representing $1.69.
› The common dividend paid in 2006 increased to $1.15 per share, providing a dividend yield of 4%.
› Our stock price increased 7.5% in 2006. Combined with the dividend yield, this produced a total return to shareholders of 11.5%.

Early in 2007, our Board of Directors increased the dividend to an indicated annual rate of $1.17 from $1.15 in 2006. We have dependably delivered dividend increases to our investors every year since 1975. We are also proud of our long history of paying dividends without interruption, which extends back to 1938. In the past 10 years, shareholder value grew at a compounded annual rate of 11.6%.

Our track record earned us recognition. We again appeared on the Mergent Dividend Achievers list, which features companies providing long-term dividend increases. And we also appeared for the second year on the financial ranking produced by *Public Utilities Fortnightly* of the country's 40 top-performing electric and gas utilities, pipelines and distribution companies.

Growth of $1,000 Investment in Otter Tail Common Stock made December 31, 1996



Shareholder value has grown at a compounded annual rate of 11.6% over the past 10 years.

2006 operational overview

The 12 operating companies of Otter Tail Corporation made good progress on goals and worked hard to deliver increased value. As in any year, some companies achieved better results than others. By investing in different industries, we are better positioned to weather economic swings within a business segment or at a specific operating company.

Our core business, Otter Tail Power Company, delivered a solid year despite challenges that reduced earnings. As expected, the earnings from wholesale energy trading were significantly lower than the record levels of a year ago. The decline was primarily a result of anticipated efficiencies in the wholesale market and lower margins on wholesale energy virtual transactions.

In the first half of 2006, our power company faced rail delivery issues that restricted coal supply at two of its three power plants. The rail delivery slowdown affected many utilities and lowered the amount of generation available for several months. Despite the challenges, the power company effectively managed the rail issues, operated at high levels of reliability and customer satisfaction and rallied with a sound performance for the year.

DIVERSIFIED FOR GROWTH UNIFIED IN PURPOSE

OUR MISSION

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.

Collectively, our nonelectric companies delivered record revenues and earnings from continuing operations in 2006:

› Our plastics segment had an outstanding year, keeping pace with demand for PVC pipe used in municipal water and wastewater systems. This segment set records in revenues and net income for a second consecutive year.

› Although results in our health services segment fell short of expectations, a new leadership team now in place has set a good foundation for improved performance in the growing healthcare industry.

› Our manufacturing companies generated significantly higher earnings due to momentum from DMI Industries, our wind energy tower manufacturer, and improved performance at BTD Manufacturing, our metal fabrication business.

› Along with the dehydrated potato industry in general, our food ingredient processing segment was caught in a cycle of scarce and higher-cost raw materials, leading to disappointing results for the year. With efforts made in 2006 to address the challenges, we expect improved results in 2007.

› Our construction companies produced significant turnarounds during the year due to strong demand in commercial, industrial and renewable energy markets.

No acquisitions or divestitures occurred in the past year other than the sale of the gas marketing operations of Otter Tail Energy Services, a small transaction. We have not stopped seeking attractive acquisition opportunities, but we will pursue to completion only when the purchase price is appropriate. We continually assess many growth options, with an emphasis on adding new companies into current operations. At present, our most ambitious growth initiatives are major capital projects within existing Otter Tail companies.

Gearing up for growth

Our resources and capital are directed to the brightest prospects for expansion and economic growth. We are seeking approvals to construct and operate a new baseload power plant, Big Stone II, which requires an intensive multi-year commitment. This would be the single largest undertaking in our company's history. The proposed 630-megawatt coal-fired plant would be built next to the existing Big Stone Plant near Milbank, South Dakota, and is expected to be operational in 2012. Electricity output would more than double at the site with no increase in emissions of sulfur dioxide, nitrogen oxides and mercury, thanks to new environmental protection technologies. In addition, the new plant would emit 20% less carbon dioxide compared with the average of other regional coal-fired plants.

Otter Tail Power Company is the lead developer/operator for Big Stone II and is working in alliance with six other utilities on the project. The Big Stone II project team is also addressing the need for increased transmission capacity. By upgrading and adding power lines, the transmission grid can accommodate electricity generated by the new plant and up to 800 megawatts from other new generation, potentially from wind energy and other forms of renewable power.

Laying the groundwork to meet future energy demand does not exclude one resource solution in favor of another. Some have condensed the issue down to a single choice of coal versus wind. But a balanced mix of generation resources is essential. It will take coal *and* wind—along with other traditional and renewable resources, effective pollution-control technology and conservation measures—to keep clean and cost-effective electricity readily available.

Wind energy is also a central part of the future at several Otter Tail companies. Our power company plans to significantly increase its renewable resources through owning dedicated wind energy facilities and by purchasing more wind energy from other developers. DMI Industries is gaining an impressive backlog of orders for wind towers. Following the successful 2006 opening of its new wind tower manufacturing plant in Canada, DMI is already expanding the

OUR VISION › To be a recognized leader in growing GREAT

OUR VALUES

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

production capacity of the Ontario operation by 30% in 2007. Another Otter Tail company, Midwest Construction Services, has developed valuable expertise in constructing underground collector systems, substations and other similar infrastructure needed in the wind energy industry. Renewable energy will play an increasingly significant role in our nation's energy future, and we are pleased to take part in building that future.

Platform leadership strengthens accountability

Each of our companies operates under our decentralized model. By applying disciplined strategic thought and execution, we reach the next level of performance together. In 2006, we strengthened our operational management structure by moving to a platform leadership model. Our goal is to keep the benefits of decentralization and develop a more responsive and accountable organization. Platform leaders are responsible to Otter Tail Corporation for the strategic and operational performance of their respective companies. In addition, each platform leader has the dual role of corporate vice president and is involved in goal setting and strategy development for Otter Tail Corporation.

We have appointed the following key executives to platform leader roles: Chuck MacFarlane, Electric Platform; Paul Wilson, Health Services Platform; Chuck Hoge, Manufacturing Platform; and Dick Nickel, Food Ingredient Processing Platform. Each has served either as the operating company leader or corporate liaison for these areas. Our plastics, construction and transportation businesses are aligned under the leadership of Shane Waslaski, formerly the CEO of Providian Consulting, who joined us at the start of 2007 to head the Infrastructure Products and Services Platform.

Diversified for growth, unified in purpose

The theme for this year's report reflects what sustains and guides us. *Diversified for growth* underscores our strategy and strength. *Unified in purpose* reflects our mission and bond. To make our mission, vision and values more memorable and meaningful, we recently revitalized the formal definitions that appear on these pages. Yet the essential tenets haven't changed. In the following pages, you will see some specific examples of our values in action. Committed people throughout our organization are working together to succeed and exceed expectations, for the good of their companies and for the good of their communities.

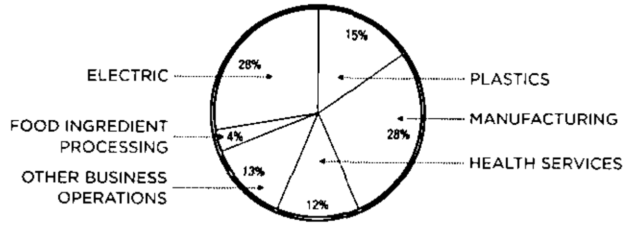
We build our businesses with a deep conviction to bring value to our customers, employees and shareholders. On behalf of more than 3,900 people working across the Otter Tail companies, we thank you for your continued investment and confidence in Otter Tail Corporation.

John Erickson
President and CEO

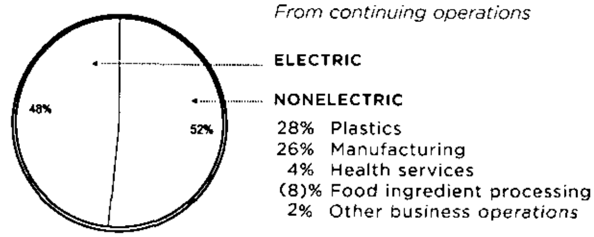
COMPANIES and developing TALENTED PEOPLE.

2006 RESULTS
For the year ended December 31, 2006

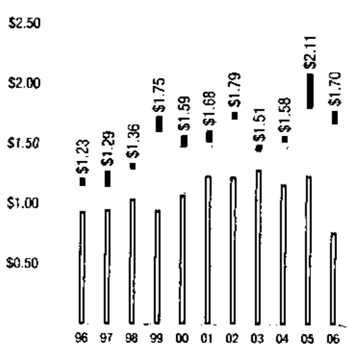
REVENUES



NET INCOME
From continuing operations



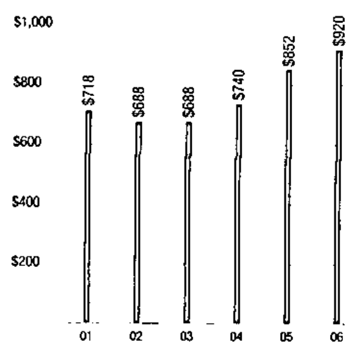
Earnings Per Share Growth



Earnings per share have grown at a compounded annual rate of 3.3% over the past 10 years.

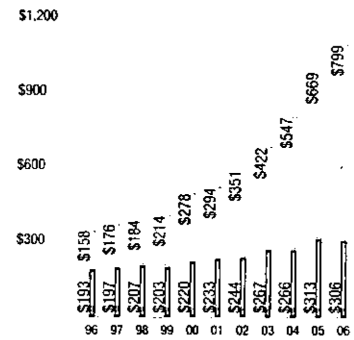
Nonelectric discontinued operations
Nonelectric continuing operations
Electric

Market Capitalization (millions)
(as of December 31)



Our market capitalization has increased 28% over the past five years. Over that same period of time, we've paid out $150 million in common dividends.

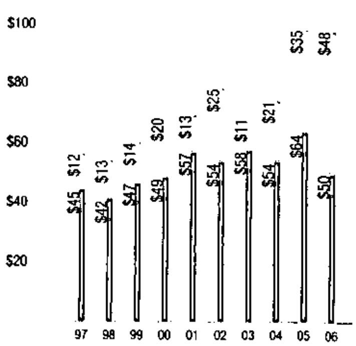
Revenue Growth (millions)



Total company revenue has grown at a compounded annual rate of 12.2% over the past 10 years.

Nonelectric
Electric

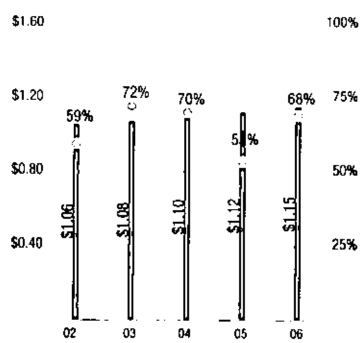
Operating Income (millions)



Operating income has grown at a compounded annual rate of 5.6% over the past 10 years.

Nonelectric
Electric

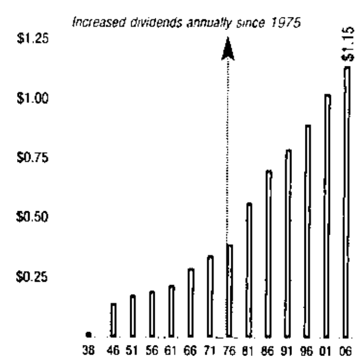
Dividend Payout Ratio



Over the past five years, dividends have increased while the average payout rate has been 64%. In 2005, earnings per share include $0.34 related to a net gain on the sale of businesses.

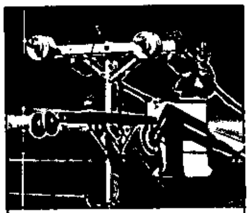
Payout Ratio
Dividend

Dividend Payment History



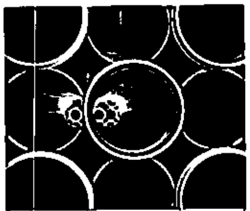
Otter Tail has paid common dividends every year since 1938 and increased those dividends each year since 1975.

OTTERTAIL CORPORATION



ELECTRIC

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



PLASTICS

Northern Pipe Products, Inc.
PVC/PE pipe manufacturer
Fargo, ND / 1995
Wayne Voorhees
125 employees
www.northernpipe.com

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

MANUFACTURING

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

DMI Industries, Inc.
Wind tower/heavy steel manufacturer
West Fargo, ND / 1990
Lars Moller
470 employees
www.dmiindustries.com

ShoreMaster, Inc.
Waterfront equipment manufacturer
Fergus Falls, MN / 2002
Erik Ahlgren
354 employees
www.shoremaster.com

T.O. Plastics, Inc.
Custom plastic parts manufacturer
Minneapolis, MN / 2001
Chuck Goers
223 employees
www.toplastics.com

HEALTH SERVICES

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

FOOD INGREDIENT PROCESSING

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

OTHER BUSINESSES

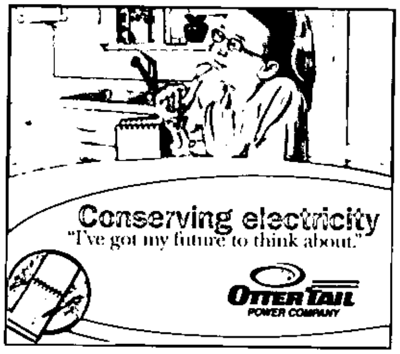
E.W. Wylie Corporation
Flatbed contract and common carrier
Fargo, ND / 1999
Marv Skar / 151 employees
95 owner/operators
www.wylietrucking.com

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

Midwest Construction Services, Inc.
Electrical and construction contractor
Moorhead, MN / 1992
Paul Bruhn / 266 employees
www.mwcsi.com

CHART LEGEND

Company Name
Company description
Location of headquarters and year acquired
Operating company leader
Employees (includes part-time and temporary)
Web site address
Map of U.S. market territory



Conserving energy
A successful ongoing campaign features a young girl, Chelsey, promoting Otter Tail Power Company's conservation website: ConservingElectricity.com. Chelsey also visited area schools with this message.

Restoring the riverbank
A riverbank project underway for six years alongside the Otter Tail River came to fruition in the summer of 2006. Nearly 1,000 feet of riverbank was recontoured to protect the area from erosion.

OTTER TAIL COMPANIES PROMOTE ENERGY CONSERVATION, SOCIAL RESPONSIBILITY AND

USING ENERGY WISELY in partnership with customers

Nearly one-third of Otter Tail Power Company's customer base—about 40,000 residential and commercial customers—take part in a demand-response program to conserve energy and reduce peak demand. This amounts to approximately 80 megawatts of electric load, or 9% of total system resources, that can be curtailed during high usage periods. Participating customers save significantly on their electricity bills. According to E Source, an international energy research organization, Otter Tail Power Company runs one of North America's most successful demand-response programs.

Improving ENERGY CONSERVATION efforts

Since introducing a conservation improvement program for Minnesota customers in 1992, Otter Tail Power Company has saved the amount of electricity that approximately 90,000 average homes would use in a year. In addition to conservation incentives offered through the Minnesota program, the power company avidly promotes energy-saving technologies and advice to all its customers across three states.

CLEANING UP WATER ISSUES and gathering steam

Concerned about the need to improve environmental controls provided by a local sanitation district, Idaho Pacific took action. The company began leasing the agricultural wastewater treatment plant in Center, Colorado, which served its potato dehydration plant and other industrial users. With the completion of major capital improvements in 2006, Idaho Pacific brought the wastewater plant's discharge levels significantly below the base requirements for environmental compliance. Odor emissions are also under control, which generated letters from grateful townspeople.

Also in 2006, the company began installing steam recovery systems at its Colorado and Idaho plants. The recaptured steam heats specific water and air processes used in manufacturing and reduces the levels of natural gas needed to run the plants.

RECYCLING makes dollars and sense:

For plastics › Otter Tail companies that manufacture plastic pipe and custom plastic packaging all recycle scrap material, which saves them money and keeps waste out of landfills. Northern Pipe Products and Vinyltech both produce PVC pipe used in municipal water and wastewater systems and meticulously reprocess nearly 100% of damaged or defective pipe and scraps for reuse. Northern Pipe invested in a new regrinding system in 2006 to keep up with pipe recycling from its plants in North Dakota and Iowa, as well as excess pipe it acquires from contractors and other pipe businesses.

For power plants › Otter Tail Power Company recycles ash byproducts from its power plants, which saves natural resources and lowers landfill use. Hoot Lake Plant markets some of its fly ash as an additive for cement pipe and concrete block. Coyote Station's bottom ash is used for sandblasting and surfacing on mining roads. All of Big Stone Plant's bottom ash goes into roofing shingles and blasting or drainage components, and some of its fly ash ends up in concrete. Using recycled ash in concrete results in a stronger product at a lower cost because fly ash is far less expensive than the traditional cement compound.

RESTORING the RIVERBANK

Otter Tail Power Company completed a major restoration effort in 2006 along the Otter Tail River near Hoot Lake Plant in Fergus Falls, Minnesota. The project involved recontouring nearly 1,000 feet of riverbank and replanting the area with grass, trees and other vegetation that will help protect it from erosion and beautify the river. Also in 2006, power company employees planted 1,500 trees at Hoot Lake Plant's ash site to absorb water and enhance the area.

Contributing to communities ›
Otter Tail Corporation promotes fitness and supports local children's charities by sponsoring the Youth Run at the Fargo Marathon, which drew more than 1,750 young runners in 2006.

Building wind energy ›
Otter Tail companies have more than 500 employees working in wind tower manufacturing and on electrical infrastructure for wind farms.

ENVIRONMENTAL STEWARDSHIP, ECONOMIC GROWTH IN THE COMMUNITIES WE SERVE

› Investing in LOWER EMISSIONS

Otter Tail Power Company invests millions of dollars in environmental controls and abides by exacting federal and state environmental regulations. In addition to complying with the existing requirements, our utility strives to go a step beyond. That is why Otter Tail participates in research projects through the University of North Dakota's Energy and Environmental Research Center. The EERC is internationally recognized as a progressive developer of cleaner, more efficient energy and environmental technologies. Through this relationship, the power company has participated in many groundbreaking studies. One of the most recent involved using Hoot Lake Plant as a host site for testing a new technology that will help play a role in resolving mercury control issues at power plants that use subbituminous coal.

Otter Tail Power Company takes environmental stewardship seriously. Since 1991, the emission of sulfur dioxide and nitrogen oxides for each kilowatt-hour of electricity generated has been reduced by more than 25%. Additionally, the power company is a partner in the EERC's Plains CO_2 Reduction Partnership, one of seven regional carbon sequestration projects across the country sponsored by the Department of Energy.

› Growing momentum in RENEWABLE ENERGY

DMI Industries grows as wind tower leader

Otter Tail companies are gaining traction in the renewable energy sector. DMI Industries is one of the nation's leading wind tower manufacturers and opened a Canadian plant in 2006 to help meet the escalating demand. The company produced nearly one-fourth of the wind towers installed in North America in 2006.

Ventus Energy Systems wires for wind and ethanol

Ventus Energy Systems, a subsidiary of Midwest Construction Services, provides wind developers with a comprehensive range of design-build electrical services and also installs medium-voltage systems for the ethanol industry. In 2006, Ventus completed electrical work on 347 megawatts of wind projects, which represents 14% of the total U.S. wind energy installations. Ventus worked on the majority of wind energy projects erected in the Upper Midwest.

Otter Tail Power Company accelerates wind power

Otter Tail Power Company also installs electrical infrastructure for wind energy facilities. And the utility offers wind as an energy source to customers, who have the option to purchase up to 100% of their electricity from the TailWinds program. The company is planning to add significant new wind generation and will increase the use of other renewable resources as well.

› GIVING BACK to our communities

Otter Tail Corporation and the 12 Otter Tail companies collectively provide nearly $1 million annually to worthy charities, non-profits and educational institutions. More than 1,000 diverse groups received contributions from Otter Tail businesses in 2006. And countless organizations benefited from our active employee base, which is committed to improving the communities where they live and work.

› Putting ECONOMIC DEVELOPMENT to work

Otter Tail Power Company's economic development efforts helped to create more than 950 jobs and save approximately 150 jobs throughout its service area in 2006. The utility's economic development team provides its expertise at no cost to the communities seeking assistance. These experts work with state and civic leaders to secure financing, find business sites and help develop a prepared workforce. The power company currently has committed nearly $800,000 to economic development loans in more than 20 communities and since 1990 has provided millions of dollars in grants and loans to assist new businesses within its service area.

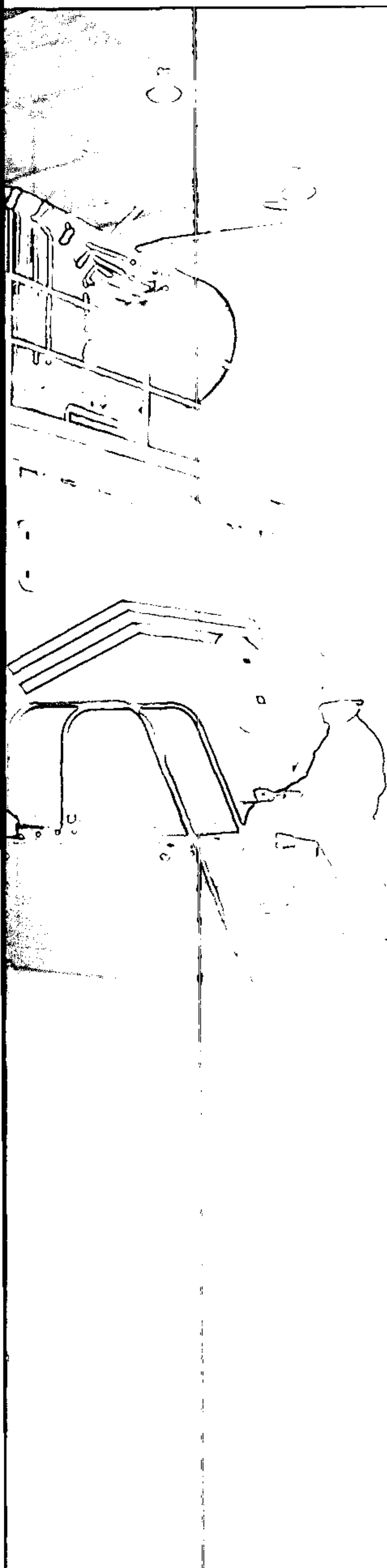
ELECTRIC

OTTER TAIL POWER COMPANY provides reliable, low-cost electricity to more than 129,000 customers in 50,000 square miles of Minnesota, North Dakota and South Dakota.

Peak demand in 2006 was 680 megawatts and total net generating capacity was 711 megawatts. In 2006, more than 9% of the energy used to serve customers came from renewable and nontraditional sources. Owned generation includes three coal-fired steam plants, six hydroelectric plants and four combustion turbine generators.

OUR POWER COMPANY WORKS NONSTOP TO DELIVER EXCELLENT

RELIABLE, LOW-COST



› Principal Engineer **BRAD ZIMMERMAN** diligently monitors the pulse of all plant operations at Coyote Station in Beulah, North Dakota. During a walk-through, he refers to diagrams while Clyde Schulz prepares to take a reading of the massive 427-megawatt generator. In 2006, Coyote Station marked 25 years of reliably delivering electricity and produced the two highest generation months ever in the plant's history.

Commitment to performance and service

Otter Tail Power Company strives to reliably meet customers' energy needs in an affordable and environmentally responsible manner. This commitment is carried out in the actions of Otter Tail employees, who serve 423 communities spanning a vast region overlapping three states. Again in 2006, these employees provided superior service, worked to keep costs among the lowest in the nation and thereby improved the quality of life for people in those many communities.

Reliability responsiveness

Reliability remains one of the surest measures of service. By responding quickly and effectively to outages, Otter Tail Power Company kept service interruptions to minimal durations. In addition to response time, the average total outage for 2006—a year with few weather-related interruptions—was less than 60 minutes per customer. This outcome is better than the average for comparable utilities and also surpassed the ambitious internal target set for the measure.

Top-tier customer service

The people served by Otter Tail Power Company recognize and appreciate such exceptional service. And customer satisfaction survey responses bear this out. The American Customer Satisfaction Index (ACSI) conducted relationship surveys in 2006 specifically for the utility with randomly selected residential customers in the three-state service territory. In comparison with ACSI's national study of major utilities, Otter Tail again scored higher than the study's highest-rated utility.

Safety achievements honored

Safety is another closely tracked measure for utilities. Otter Tail Power Company ranked among the best for safety results in 2006 by the Edison Electric Institute, the national association of shareholder-owned electric companies.

The Minnesota Safety Council bestowed its 2006 Award of Honor on Otter Tail for continued excellence in safety throughout all utility operations.

Employees at Big Stone Plant accepted the South Dakota Safety Council's Outstanding Achievement Award for accident prevention and workplace safety.

Coyote Station received the North Dakota Safety Council's Presidential Citation for occupational safety. In addition, Coyote Station received the North Dakota Lignite Energy Council Safety Award for posting the best safety record among the 12 plants and mines in the state.

Coyote Station sets service landmarks

In May 2006, Coyote Station marked 25 years of reliably delivering electricity to a multi-state area and contributing to the area economy in central North Dakota.

In July, the plant set an all-time monthly record for generation, breaking the prior record set 10 years earlier. And it didn't take long to exceed the new target. The next record-breaking month came consecutively in August, with 298,815 net megawatt-hours, which equals a 401.6 net megawatts-per-hour average for the entire month.

Otter Tail Power Company operates the 427-megawatt Coyote Station and owns 35% of the plant generation.

SERVICE AND GENERATE ELECTRICITY THAT IS

AND ENVIRONMENTALLY RESPONSIBLE

Rail delivery issues resolved

Rail transportation issues escalated in the first half of 2006. Slower and fewer coal shipments from Wyoming's Powder River Basin curtailed capacity at Big Stone Plant in South Dakota and Hoot Lake Plant in Minnesota. Through concentrated efforts, Otter Tail Power Company successfully managed the slowdown without diminishing reliability and worked to improve rail delivery issues. Rail cycle times improved by September, and the plants leased additional rail cars and regained the coal levels needed to run at full-load capacity.

Transmission goals in sight

Otter Tail Power Company is working collaboratively with 10 other utilities to develop transmission to increase reliability for Minnesota and the surrounding region over the next several years. Dubbed CapX 2020 for capacity expansion by the year 2020, the project is entering the regulatory and implementation phase. The utilities are seeking regulatory approval for approximately 600 miles of 345-kilovolt lines in Minnesota with short segments in North Dakota, South Dakota and Wisconsin. Regulatory filings for a smaller 230-kilovolt line in north-central Minnesota also are planned.

Otter Tail Power Company owns nearly 5,300 miles of transmission lines and continues to invest in the grid to ensure reliable and adequate delivery systems for its customers. Growing demand in southwestern Minnesota has created the need for additional transmission capacity. Pending regulatory approval, the power company will upgrade 40 miles of line between Appleton and Canby, Minnesota, in 2007.

Renewables top list of balanced generation

Preparing well for future energy needs requires the ability to draw from diverse and balanced energy resources. Otter Tail Power Company believes the optimal future resource mix will include additional resources in wind, coal, coal gasification, hydro, natural gas, conservation and energy efficiency. Among all these resources, including Otter Tail's portion of baseload capacity from Big Stone II, the largest increase in the coming years would be from wind energy and other renewables. The power company is pursuing opportunities to have a substantial portion of the new wind generation operational in late 2007 or early 2008.

Big Stone II developments

Otter Tail Power Company, in cooperation with six other regional power suppliers, continued to plan for Big Stone II, a proposed 630-megawatt electric generating station to be constructed adjacent to the existing Big Stone Plant in northeastern South Dakota. Big Stone II would serve as a baseload facility by providing round-the-clock electrical energy and supporting regional electric reliability. Otter Tail's projected share is approximately 20% of the plant's net capability.

By using new proven technologies in environmental protection equipment, emissions of sulfur dioxide, nitrogen oxides and mercury from the two Big Stone plants would be equal to or lower than they are now with a single plant. And, due to additional technology investments, the new plant would emit 20% less carbon dioxide than the average of other existing coal-fired plants in the region.

Much work is underway on the proposed plant. Although challenges remain, a great deal has been accomplished. The Big Stone II participants have secured four of the eight major required permits. The project would require constructing 140 miles of transmission line and six new or upgraded substations. Nearly all of the transmission rights-of-way have been secured through the South Dakota transmission corridors with solid landowner cooperation—a result of Otter Tail employees' attention to landowner concerns. Assuming all required permits are obtained in 2007, groundbreaking could take place in early 2008 with an on-line date anticipated by mid-2012.

Future direction

Finalizing the remaining permits for Big Stone II is a top priority for 2007. Another priority—unrelated to Big Stone II—is preparing for filing a rate case in Minnesota, Otter Tail's first rate increase request in more than 20 years. Development of wind energy facilities will also be clearly on the horizon in 2007. Otter Tail Power Company employees will continue to work diligently to improve results in key measures of reliability, plant availability, customer satisfaction, safety and financial performance.

› Line Operator **JILL WALDEN** moves at a swift pace during her shift at Northern Pipe Products in Fargo, North Dakota. She and her work team expertly run extrusion lines, oversee quality testing and forklift numerous pipe loads, moving seamlessly between shared duties. Along with sister company Vinyltech, the highly motivated crews at Northern Pipe generated excellent results in 2006.

PLASTICS

Pipe companies produce exceptional results

The plastic pipe segment delivered a second consecutive year of record revenues and earnings. Excellent production and sales volumes resulted in strong earnings as the companies kept pace with construction demand for quality water and wastewater pipe.

Vinyltech reaches peak production

Vinyltech reached record pipe production levels in May. The Phoenix-based operation continued to move ahead on a major plant expansion in 2006, which is expected to be fully operational by 2008. The addition of a larger state-of-the-art resin-blending system and two additional extrusion lines will increase production capacity by 40%.

Northern Pipe increases throughput

Investment in a new regrinding system that recycles almost 100% of discarded pipe into usable resin increased throughput at Northern Pipe Products' plant in Fargo, North Dakota. The company's Hampton, Iowa, plant introduced a new product line of polyethylene drain tile. Showcasing an innovative approach to reducing turnover and improving quality, Northern Pipe's self-directed work team concept is chronicled in a book published in 2006 by the American Society for Quality.

NORTHERN PIPE PRODUCTS, INC., manufactures and sells PVC and polyethylene pipe used in municipal water, rural water, wastewater and storm drainage systems in the Northern, Midwestern and Western regions of the United States as well as in Canada.

VINYLTECH CORPORATION manufactures and sells PVC pipe used in municipal water, wastewater and water reclamation systems in the South-central, Southwestern and Western regions of the United States.

OUR PIPE COMPANIES KEEP UP WITH DEMAND FOR QUALITY PIPE PRODUCTS

MANUFACTURING

BTD MANUFACTURING, INC., provides metal fabrication services for custom machine parts and metal components through metal stamping, tool and die, machining, tube bending, welding and assembly.

DMI INDUSTRIES, INC., manufactures wind towers and other heavy steel-fabricated products.

SHOREMASTER, INC., produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems.

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.

OUR MANUFACTURING COMPANIES RELENTLESSLY TOP PRODUCTIVITY

› Industrial Painter **NEDZAD MUJIC** pauses to check his work after spraying on the finishing coat for a 100-foot tower section—one of three sections that go into a complete wind tower—at DMI Industries in West Fargo, North Dakota. In 2006, Ned was part of a crew of experienced welders, painters, assemblers and other staff who traveled to DMI's new plant in Fort Erie, Ontario, to help train in their Canadian counterparts. The expansion solidifies DMI as one of North America's largest manufacturers of wind energy towers.

DMI Industries increases capacity

DMI Industries delivered excellent results in 2006 that elevated performance for Otter Tail's manufacturing platform.

The company initiated production at its new Canadian wind energy tower plant in early 2006. Staff from DMI's home base in West Fargo, North Dakota, provided technology transfer and expert training to their counterparts in Fort Erie, Ontario.

The crew at DMI's new plant is already preparing to increase capacity by 30% in 2007. With its two plants, DMI is further established as one of the largest tower manufacturing operations in North America.

DMI also increased capacity at its West Fargo plant by focusing on process improvements and efficiency measures. DMI added more fabrication for smaller-scale parts assembled within towers and began contracting with sister company BTD Manufacturing to supply some of these internal components.

As turbines get larger, so do the supporting towers, and DMI is a recognized leader in producing the next generation of larger wind towers. In 2006, DMI worked with major wind turbine manufacturers to meet exacting specifications required for each company's respective towers.

The extension of wind production tax credits through 2008 came as a welcome signal of federal support for the increasingly robust wind energy industry.

BTD leverages locations and learning

BTD Manufacturing had strong performance in 2006 due to improved labor productivity. The company added manufacturing capabilities at its Lakeville site near Minneapolis. This location, which is also a distribution center, keeps BTD in closer proximity to existing metro-area customers as well as new market opportunities. Some consolidation also took place by relocating machining operations to the main plant in Detroit Lakes, Minnesota, from a nearby community. BTD placed high emphasis on people development and training opportunities in 2006, working to establish the company as an employer of choice throughout the region.

ShoreMaster sales lift

Despite a general slowdown in commercial business, ShoreMaster's residential sales of waterfront products reached record levels. The commercial side gained momentum later in the year as ShoreMaster aggressively pursued bidding opportunities, and the company's Missouri operations gained solid backlog into 2007. ShoreMaster completed the acquisition of Aviva Sports in February 2007. Aviva is a Missouri-based manufacturer of inflatable recreational water toys sold worldwide.

T.O. Plastics heats up productivity

With pricing pressures throughout the thermoforming industry, T.O. Plastics invested in capital and productivity improvements to reduce costs. Installing a new thermoforming production line resulted in a 30% throughput gain and more capital upgrades are planned for 2007. The company introduced several new product offerings in 2006, which were well received by customers. A building addition at the main plant in Clearwater, Minnesota, added much-needed office space and allowed for manufacturing expansion.

WORK TO DELIVER AND EXCEPTIONAL PRODUCTS

HEALTH SERVICES

› Service Systems Specialist **TOM KEMPER** inspects the sophisticated inner workings of a Philips 64-slice scanner in a cardiac CT mobile unit. He ensures this new addition to the DMS Health Group fleet is ready to hit the road for its next destination: Walter Reed Army Medical Center in Washington, D.C. Based in Fargo, North Dakota, the DMS Health Group provides diagnostic imaging equipment, supplies and services to healthcare providers nationwide.

Expanding territory and services

Health services revenues increased 9% in 2006, led by strong performance in the imaging business. This was tempered by a rise in equipment-related costs, which lowered earnings. DMS Health Group expanded its service territory as well as service offerings in 2006. Mobile imaging operations in the company's east region began serving hospitals in four additional East Coast states and Washington, D.C. Portable X-ray operations outfitted 12 vans in the fleet with wireless transmission capabilities so images can be sent instantly for radiologist review, producing a more immediate diagnosis. For the third year in a row, DMS Health Group was voted a top vendor in the 2006 *Medical Imaging* Readers' Choice Awards.

New leadership appointments

DMS Health Group's CEO Paul Wilson assembled his senior leadership team in 2006. Mark Doda, previously the DMS CFO, was named president of DMS Imaging. Early in 2007, Tom Andersson, a vice president at Fuji Medical Systems, USA, accepted the role of president of DMS Health Technologies. With these appointments and other top leadership assignments in place, the DMS team is focusing on operational planning processes, improving cost controls and strengthening the infrastructure for sustainable growth.

DMS HEALTH GROUP is composed of two primary business units that deliver diagnostic imaging and healthcare solutions across the nation.

DMS Health Technologies sells and installs diagnostic medical imaging systems, patient monitoring equipment and medical supplies and provides ongoing service maintenance. DMS Health Technologies also is a major distributor for Philips Medical Systems.

DMS Imaging provides shared diagnostic medical imaging services for MRI, CT, nuclear medicine, PET/CT, ultrasound, mammography and bone density testing. Delivery of services is through DMS Imaging mobile units with options available for interim and fixed-site delivery. DMS Imaging also provides portable X-ray, ultrasound and EKG services.

OUR HEALTH SERVICES COMPANY DELIVERS STATE-OF-THE-ART SOLUTIONS

› Plant Sanitarian **MIREYA MOLINA** performs an intense clean sweep at Idaho Pacific's processing plant in Ririe, Idaho. With her daily checklist of more than 50 inspection points, she supervises staff who keep the plant and equipment sanitized and up to the exacting requirements of federal and customer auditors. Idaho Pacific is a leading supplier of dehydrated potato products to major food processors for use in hundreds of food items.

FOOD INGREDIENT PROCESSING

A challenging year, ongoing improvements

Overall results were disappointing in food ingredient processing for 2006 largely due to industrywide shortages in potatoes. Idaho Pacific targeted its primary challenges by increasing plant and energy efficiencies and addressing raw material availability and costs.

The mid-year unveiling of a new product line in the foodservice channel met with good response. Energy costs were lowered at two plants with the installation of an effective steam-recovery process, which will be fully phased in across all three locations in 2007. Idaho Pacific anticipates improved performance in 2007 with excellent sales backlog at its three plants, decreased natural gas costs, a more favorable currency exchange rate and access to raw material supplies.

The company also gained an upswing in exports to the European dehydrated market due to crop problems overseas. Export opportunities are expected to continue into 2007 and extend to other international markets as well.

IDAHO PACIFIC HOLDINGS, INC., manufactures and supplies dehydrated potato products to food-manufacturing customers in the snack food, foodservice and bakery industries.

OUR FOOD COMPANY'S DEHYDRATED PRODUCTS ARE SERVED THROUGHOUT THE WORLD

OTHER BUSINESSES

> CONSTRUCTION
> TRANSPORTATION

› Senior Vice President and Chief Administrative Officer **SHARON WHISTLER** is hands-on with the inner workings at Foley Company, where she oversees accounting, human resources, IT and administration. She holds the longest employee tenure at the Kansas City, Missouri-based construction company and is a key member of the team that helped build Foley into a major mechanical contracting firm.

Construction companies building up

Foley Company's workload greatly increased in 2006 with successful bids on construction opportunities across a multi-state region and within its hometown of Kansas City, Missouri. Some of Foley's larger projects include acting as general contractor for a major wastewater treatment plant in Sioux City, Iowa, and as mechanical contractor for the Sprint Center, a new 18,500-seat sports arena in Kansas City.

Midwest Construction Services is honing its reputation for electrical construction expertise within the renewable energy sector. Its subsidiary, Ventus Energy Systems, installed the complete electrical packages for several wind farms—including substations and transmission—as well as medium-voltage systems for ethanol plants. At a 133-turbine wind farm near Fenton, Minnesota, Ventus plowed in more than 100 miles of underground medium-voltage cable. Another subsidiary, Aerial Contractors, had a record year, responding to huge demand for transmission and distribution projects.

Trucking company draws drivers

Driver recruitment, a nationwide challenge in the trucking industry, remained a top priority at E.W. Wylie in 2006. The firm made good inroads with attracting company drivers as well as additional truck owner/operators, nearly doubling these partnerships during the year. This development, along with the addition of company-owned trucks, increased the fleet by nearly 30%.

E.W. WYLIE CORPORATION operates a fleet of approximately 220 trucks (125 company trucks and 95 owner/operator trucks) as a flatbed contract and common carrier across the lower 48 United States and Canada.

FOLEY COMPANY provides mechanical and prime contracting for water and wastewater treatment plants, hospital and pharmaceutical facilities, power generation plants and other industrial and manufacturing projects.

MIDWEST CONSTRUCTION SERVICES, INC., provides a full spectrum of electrical design and construction services for the industrial, commercial and municipal business markets, including government, institutional, communications, utility and renewable energy projects.

OUR CONSTRUCTION FIRMS AND TRUCKING COMPANY ARE ON A ROLL WITH SUPERIOR SERVICE

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands, except number of shareholders and per-share data)	**2006**	2005	2004	2003	2002	2001	1996
Revenues							
Electric	**$ 306,014**	$ 312,985	$ 266,385	$ 267,494	$ 244,005	$ 232,720	$ 192,849
Plastics	**163,135**	158,548	115,426	86,009	82,931	63,216	22,049
Manufacturing	**311,811**	244,311	201,615	157,401	119,880	96,571	34,819
Health services	**135,051**	123,991	114,318	100,912	93,420	79,129	61,697
Food ingredient processing	**45,084**	38,501	14,023	—	—	—	—
Other business operations (1)	**147,436**	107,400	104,002	79,427	56,225	54,934	39,714
Intersegment eliminations	**(3,577)**	(3,867)	(2,733)	(2,254)	(1,036)	—	—
Total operating revenues (1)	**$ 1,104,954**	$ 981,869	$ 813,036	$ 688,989	$ 595,425	$ 526,570	$ 351,128
Net income from continuing operations (1)	**50,750**	53,902	40,502	38,297	44,297	39,697	28,905
Net income from discontinued operations (1)	**362**	8,649	1,693	1,359	1,831	3,906	1,719
Net income	**51,112**	62,551	42,195	39,656	46,128	43,603	30,624
Operating cash flow from continuing operations (1)	**79,207**	90,348	54,410	76,464	71,584	71,010	66,356
Operating cash flow— continuing and discontinued operations	**80,246**	95,800	56,301	76,955	76,797	77,529	68,611
Capital expenditures—continuing operations (1)	**69,448**	59,969	49,484	48,783	73,442	50,723	63,335
Total assets	**1,258,650**	1,181,496	1,134,148	986,423	914,112	817,778	703,881
Long-term debt	**255,436**	258,260	261,805	262,311	254,015	221,643	153,452
Redeemable preferred	**—**	—	—	—	—	—	18,000
Basic earnings per share—continuing operations (1) (2)	**1.70**	1.82	1.53	1.47	1.73	1.53	1.15
Basic earnings per share—total (2)	**1.71**	2.12	1.59	1.52	1.80	1.69	1.23
Diluted earnings per share—continuing operations (1) (2)	**1.69**	1.81	1.52	1.46	1.72	1.52	1.15
Diluted earnings per share—total (2)	**1.70**	2.11	1.58	1.51	1.79	1.68	1.23
Return on average common equity	**10.6%**	13.9%	12.0%	12.2%	15.3%	15.5%	14.9%
Dividends per common share	**1.15**	1.12	1.10	1.08	1.06	1.04	0.90
Dividend payout ratio	**68%**	53%	70%	72%	59%	62%	73%
Common shares outstanding—year end	**29,522**	29,401	28,977	25,724	25,592	24,653	23,072
Number of common shareholders (3)	**14,692**	14,801	14,889	14,723	14,503	14,358	13,829

Notes: (1) Prior years are restated to exclude OTESCO's gas marketing operations, which were sold in 2006 and are now classified as discontinued. See note 16 to consolidated financial statements.
(2) Based on average number of shares outstanding.
(3) Holders of record at year end.

SELECTED ELECTRIC OPERATING DATA

	2006	2005	2004	2003	2002	2001	1996
Revenues (thousands)							
Residential	**$ 86,950**	$ 83,740	$ 76,365	$ 75,689	$ 72,180	$ 69,882	$ 66,295
Commercial and farms	**101,895**	100,677	88,853	88,550	84,143	79,227	74,355
Industrial	**65,370**	61,235	54,159	48,315	45,803	45,813	37,453
Sales for resale	**25,965**	31,768	27,228	29,702	18,295	23,255	3,742
Other electric	**25,834**	35,565	19,780	25,238	23,584	14,543	11,004
Total electric	**$ 306,014**	$ 312,985	$ 266,385	$ 267,494	$ 244,005	$ 232,720	$ 192,849
Kilowatt-hours sold (thousands)							
Residential	**1,170,841**	1,162,765	1,119,067	1,141,612	1,130,770	1,098,149	1,082,926
Commercial and farms	**1,453,664**	1,428,059	1,386,358	1,396,638	1,383,129	1,318,569	1,265,532
Industrial	**1,297,287**	1,233,948	1,197,534	1,108,021	1,106,241	1,117,482	992,979
Other	**69,062**	69,663	70,105	70,071	70,447	71,450	91,826
Total retail	**3,990,854**	3,894,435	3,773,064	3,716,342	3,690,587	3,605,650	3,433,263
Sales for resale	**2,778,460**	2,778,431	3,845,299	3,786,397	3,049,786	2,830,079	636,664
Total	**6,769,314**	6,672,866	7,618,363	7,502,739	6,740,373	6,435,729	4,069,927
Annual retail kilowatt-hour sales growth	**2.5%**	3.2%	1.5%	0.7%	2.4%	2.9%	4.0%
Heating degree days	**8,260**	8,656	9,132	9,132	9,065	8,598	10,572
Cooling degree days	**517**	423	228	515	623	651	456
Average revenue per kilowatt-hour							
Residential	**7.43¢**	7.20¢	6.82¢	6.63¢	6.38¢	6.36¢	6.12¢
Commercial and farms	**7.01¢**	7.05¢	6.41¢	6.34¢	6.08¢	6.01¢	5.88¢
Industrial	**5.04¢**	4.96¢	4.52¢	4.36¢	4.14¢	4.10¢	3.77¢
All retail	**6.54¢**	6.39¢	5.95¢	5.85¢	5.61¢	5.52¢	5.35¢
Customers							
Residential	**101,657**	101,176	100,952	100,515	100,092	99,667	98,039
Commercial and farms	**26,343**	26,211	26,157	25,900	25,950	25,825	25,634
Industrial	**42**	44	40	40	41	42	37
Other	**1,028**	1,035	1,069	1,079	1,074	1,084	1,072
Total electric customers	**129,070**	128,466	128,218	127,534	127,157	126,618	124,782
Residential sales							
Average kilowatt-hours per customer (4)	**11,706**	11,749	11,251	11,525	11,504	11,306	11,251
Average revenue per residential customer	**$ 862.99**	$ 776.48	$ 766.99	$ 756.83	$ 732.64	$ 716.93	$ 688.80

Notes: (4) 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 straightforward: Reliable utility performance combined with growth opportunities at all our businesses provides long-term value. This includes growing our core electric utility business which provides a strong base of revenues, earnings and cash flows. In addition, we look to our nonelectric operating companies to provide growth both organically and through acquisitions. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. We 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 results. In doing this, we also avoid concentrating business risk within a single industry. All 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 will divest operating companies that do not meet these criteria over the long term.

The following major events occurred in our company in 2006:

- Our annual consolidated revenues topped $1.1 billion for the first time in our history.
- We reported record earnings in our plastics, manufacturing and construction operations.
- We continued to work with six other regional utilities on the planning and permitting process for a new 630-megawatt coal-fired electric generating plant (Big Stone II) on the site of the existing Big Stone Plant.

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

- Planned capital budget expenditures of up to $889 million for the years 2007-2011 of which $776 million is for capital projects at the electric utility, including $360 million related to Big Stone II, $64 million for a wind generation project and $59 million for anticipated expansion of transmission capacity in Minnesota. See "Capital Requirements" section for further discussion.
- Pursuing the regulatory approvals, financing and other arrangements necessary to build Big Stone II.
- Adding more renewable energy to our electric resource mix.
- Increasing wind tower production through expansion and continued improvements in productivity, including an increase of DMI's production capacity by 30% at its Ft. Erie, Ontario facility.
- Focus on improving the operating results of Idaho Pacific Holdings, Inc. (IPH).
- The continued investigation and evaluation of strategic acquisition opportunities.

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

(in thousands)	2006	2005
Operating revenues:		
Electric	$ 305,703	$ 312,624
Nonelectric	799,251	669,245
Total operating revenues	$1,104,954	$ 981,869
Net income from continuing operations:		
Electric	$ 24,181	$ 37,301
Nonelectric	26,569	16,601
	50,750	53,902
Net income from discontinued operations	362	8,649
Total net income	$ 51,112	$ 62,551

The 12.5% increase in consolidated revenues in 2006 compared with 2005 reflects revenue growth in all our business segments except electric. Revenues increased $67.5 million in our manufacturing segment in 2006 as a result of increased sales of wind towers and price increases related to higher raw material costs. Other business operations revenue grew by $40.0 million in 2006, with $35.6 million coming from our construction companies as a result of increased construction activity and $4.5 million coming from flatbed trucking operations as a result of more miles driven combined with higher fuel costs. Revenues from our health services segment increased $11.1 million in 2006. Scanning and other related service revenues were up $8.0 million while revenues from equipment sales and service increased $3.1 million between the years. Revenues in our food ingredient processing segment increased $6.6 million in 2006 mainly as a result of a 15.3% increase in the price per pound of product sold. Revenues grew $4.6 million in our plastics segment in 2006 despite an 8.8% decrease in pounds of pipe sold primarily as a result of price increases driven by higher resin prices for polyvinyl chloride (PVC) pipe. Revenues in the electric segment decreased $6.9 million reflecting a $20.4 million decrease in wholesale energy revenues, partially offset by increases of $12.0 million in retail electric revenue and $1.5 million in other electric revenue.

An $18.8 million decrease in net revenues from energy trading activities in 2006 compared with 2005 was the main contributing factor to the $13.1 million reduction in electric segment net income, as the electric wholesale market became more efficient. Record net income from our manufacturing segment and construction companies contributed to the $10.0 million increase in net income from our nonelectric business segments between the years.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2006, 2005 and 2004, followed by our outlook for 2007, a discussion of our financial position at the end of 2006 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 found elsewhere in this report. 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 segment tables that follow for 2006, 2005 and 2004 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)	2006	2005	2004
Operating revenues:			
Electric	$ 311	$ 361	$ 365
Nonelectric	3,266	3,506	2,368
Cost of goods sold	1,433	2,070	1,083
Other nonelectric expenses	2,144	1,797	1,650

ELECTRIC

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

(in thousands)	2006	% change	2005	% change	2004
Retail sales revenues	$260,926	5	$248,939	11	$224,326
Wholesale revenues	25,514	(39)	41,953	75	24,000
Net marked-to-market gains	451	(90)	4,444	38	3,228
Other revenues	19,123	8	17,649	19	14,831
Total operating revenues	$306,014	(2)	$312,985	17	$266,385
Production fuel	58,729	5	55,927	7	52,056
Purchased power—system use	58,281	(1)	58,828	47	40,098
Other operation and maintenance expenses	103,548	4	99,904	17	85,361
Depreciation and amortization	25,756	6	24,397	1	24,236
Property taxes	9,589	(5)	10,043	(4)	10,411
Operating income	$ 50,111	(22)	$ 63,886	18	$ 54,223

2006 compared with 2005

The $12.0 million increase in retail electric revenue in 2006 compared with 2005 is due mainly to a $9.5 million increase in fuel clause adjustment (FCA) revenues related to increases in fuel and purchased power costs for system use and to a $3.6 million increase in FCA revenue related to the 2006 reversal of a $1.9 million FCA refund provision recorded in December 2005. The refund provision is related to Midwest Independent Transmission System Operator (MISO) costs subject to collection through the FCA in Minnesota. In December 2005, the Minnesota Public Utilities Commission (MPUC) issued an order denying recovery of certain MISO-related costs through the FCA and requiring a refund of amounts previously collected. In February 2006, the MPUC reconsidered its order and eliminated the refund requirement. In December 2006, the MPUC ordered the refund of $0.4 million in MISO schedule 16 and 17 administrative costs that had been collected through the FCA, allowing for deferred recovery of those costs in the electric utility's next general rate case which is scheduled to be filed on or before October 1, 2007. The FCA revenues also include $2.6 million in unrecovered fuel and purchased power costs under an FCA true-up mechanism established by order of the MPUC. The Minnesota FCA true-up relates to costs incurred from July 2004 through June 2006 that are being recovered from Minnesota customers from August 2006 through July 2007. The electric utility currently is accruing for the Minnesota FCA true-up on a monthly basis along with its regular monthly FCA accrual.

Retail megawatt-hour (mwh) sales increased 2.5% between the years as a result of increased sales to industrial customers mainly due to increased consumption by pipeline customers as higher oil prices have led to an increase in the volume of product being transported from Canada and the Williston basin. A 9.8% decline in the price of wholesale mwh sales from company-owned generation in 2006 compared with 2005 resulted in a $1.7 million decrease in revenues despite a 3.4% increase in mwh sales from company-owned generating units. Advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006 due to unseasonably mild weather. Wholesale sales from company-owned generation were curtailed in February and March 2006 as generation levels were restricted due to coal supply constraints at Big Stone and Hoot Lake plants. Advance purchases of electricity in anticipation of continuing coal supply constraints in the second quarter of 2006 supplemented increased generation when coal supplies improved in May, providing additional resources for wholesale sales.

Net revenue from energy trading activities, including net mark-to-market gains on forward energy contracts, were $2.8 million in 2006 compared with $21.6 million in 2005. The $18.8 million decrease in revenue from energy trading activities reflects an $11.4 million reduction in net profits from virtual transactions, a $4.5 million reduction in profits from purchased power resold and a $4.0 million decrease in net mark-to-market gains on forward energy contracts, offset by a $1.1 million increase in profits from investments in financial transmission rights (FTRs). With the inception of the Midwest MISO Day 2 markets in April 2005, MISO introduced two new types of contracts, virtual transactions and FTRs. Virtual transactions are of two types: (1) a Virtual Demand Bid, which is a bid to purchase energy in MISO's Day-Ahead Market that is not backed by physical load; (2) a Virtual Supply Offer, which is an offer submitted by a market participant in the Day-Ahead Market to sell energy not supported by a physical injection or reduction in withdrawals in commitment by a resource. An FTR is a financial contract that entitles its holder to a stream of payments, or charges, based on transmission congestion charges calculated in MISO's Day-Ahead Market. A market participant can acquire an FTR from several sources: the annual or monthly FTR allocation based on existing entitlements, the annual or monthly FTR auction, the FTR secondary market or FTRs granted in conjunction with a transmission service request. An FTR is structured to hedge a market participant's exposure to uncertain cash flows resulting from congestion of the transmission system. Profits from virtual transactions were $1.2 million in 2006 compared with $12.7 million in 2005 as the MISO market matured and became more efficient and as a result of a reduction in virtual transactions due to uncertainties related to the status of Revenue Sufficiency Guarantee charges in MISO's Transmission and Energy Markets Tariff. In 2006, we recorded a net loss on purchased power resold of $1.8 million compared with a net gain of $2.7 million in 2005. Of the $2.9 million in net mark-to-market gains recognized on open forward energy contracts at December 31, 2005, $2.1 million was realized and $0.8 million was reversed in the first nine months of 2006 as market prices on forward electric contracts declined in response to decreased demand for electricity due, in part, to regional winter weather that was milder than expected.

The $2.8 million increase in fuel costs in 2006 compared with 2005 reflects a 3.2% increase in the cost of fuel per mwh generated combined with a 1.8% increase in mwhs generated. Generation used for wholesale electric sales increased 3.4% while generation for retail sales increased 1.3% between the periods. Fuel costs per mwh increased at the Coyote Station and Hoot Lake Plant as a result of increases in coal and coal transportation costs between the periods. Much of the increase in coal and coal transportation costs is related to higher diesel fuel prices. The mix of available generation resources in 2006 compared with 2005 also contributed to the increase in the cost of fuel per mwh generated. Big Stone Plant's generation increased 12.9% between the years while Coyote Station's generation was down 5.9%. In the second quarter of 2006, Coyote Station, our lowest cost baseload plant, was off-line for five weeks for scheduled maintenance. In the second quarter of 2005, the higher cost Big Stone Plant was shut down for seven weeks for scheduled maintenance. Approximately 90% of the fuel cost increases associated with generation to serve retail electric customers is subject to recovery through the fuel cost recovery component of retail rates.

The $0.5 million decrease in purchased power—system use (to serve retail customers) in 2006 compared with 2005 is due to a 20.9% reduction in mwh purchases for system use mostly offset by a 25.2% increase in the cost per mwh purchased for system use.

The $3.6 million increase in other operation and maintenance expenses for 2006 compared with 2005 resulted primarily from $2.0 million in increased operating and maintenance costs at the electric utility's generation plants, including Coyote Station, which was shut down for five weeks of scheduled maintenance in the second quarter of 2006, and $1.4 million in increased costs related to contract work performed for other area utilities. Depreciation expense increased $1.4 million in 2006 compared with 2005 as a result of an increase in effective depreciation rates in 2006 and increases in electric plant in service. The $0.5 million decrease in property taxes reflects lower property valuations in Minnesota and South Dakota.

2005 compared with 2004

The $24.6 million increase in retail revenues from 2004 to 2005 includes $16.0 million in increased FCA revenues directly related to increases in fuel and purchased power costs in 2005 and $8.6 million from a 3.2% increase in retail mwh sales. Residential mwh sales increased 3.9% primarily due to an 86% increase in cooling degree-days in the summer of 2005 compared with the summer of 2004. Mwh sales to commercial and industrial customers increased 3.0% due to an improving regional economy.

Wholesale revenues increased $18.0 million in 2005 compared with 2004. In 2005, we recorded $12.7 million in net revenues related to virtual transactions and $1.9 million in net revenue related to bilateral trading of FTRs in MISO's secondary market. Net revenues from the purchase and sale of electric energy contracts, including virtual transactions and FTRs, increased $11.2 million in 2005 compared with 2004 as a result of a 178% increase in mwh volume traded between the years. Revenues from wholesale energy sales from company-owned generation increased $6.8 million due to a 58.9% increase in the average price per mwh sold in 2005 compared with 2004, offset by a 13.2% reduction in mwh sales. The increase in the average price per mwh is reflective of a general increase in energy prices in 2005 related to increased fuel costs.

The $1.2 million increase in net mark-to-market gains on forward energy contracts is due to an increase in the volume of forward energy contracts entered into in 2005 compared to 2004 combined with increasing energy prices in 2005. At December 31, 2005 the electric utility had recorded $2.9 million in net gains on forward energy contracts to be settled in 2006 compared with $0.3 million in recorded net gains on forward energy contracts at December 31, 2004 that were settled in 2005.

The $2.8 million increase in other electric revenues in 2005 compared with 2004 is related mostly to transmission studies completed by Otter Tail Power Company for MISO and transmission line permitting work done for other companies.

In December 2005, the MPUC issued an order denying the 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. A $1.9 million reduction in revenue and a refund payable was recorded in December 2005 by the electric utility to reflect the refund obligation.

The $3.9 million increase in production fuel costs in 2005 compared with 2004 reflects a 15.5% increase in the cost of fuel per mwh generated, partially offset by a 7.0% reduction in generation. The decrease in mwhs generated is mainly due to the seven-week maintenance shutdown of the Big Stone Plant in 2005. Fuel costs per mwh of generation increased at all three of our coal-fired generating plants as a result of increases in mine operating costs and, in the case of Hoot Lake and Big Stone plants, increased costs for transporting coal by rail. Much of the increase in mine operating and coal transportation costs is directly related to a sharp increase in diesel fuel prices in 2005. Also, the overall increase in production fuel costs is partially attributable to our generation mix in 2005. Mwh generation at our higher cost Hoot Lake generating units increased 25% in 2005 compared with 2004 while mwh generation at our lower cost Big Stone and Coyote generating units decreased 21% and 6% respectively. Fuel costs at our combustion turbine peaking plants increased $2.5 million (110%) while mwh generation increased by only 7.6%, reflecting increases in natural gas and fuel oil prices in 2005 and decreased plant efficiencies resulting from MISO dispatch directives.

Purchased power costs to serve retail customers increased $18.7 million as a result of a 28.2% increase in mwh purchases combined with a 14.5% increase in the cost per mwh purchased. Mwh purchases increased to make up for the shortfall caused by the Big Stone Plant shutdown and to provide for increased demand among retail electric customers. The increase in the cost per mwh of purchased power in 2005 is partially due to increases in fuel costs and partially due to a decrease in available electricity from hydro-generation in the region due to lower water levels in Upper Missouri River reservoirs resulting from a prolonged drought in the Upper Missouri River Basin.

The $14.5 million increase in other operation and maintenance expenses in 2005 compared with 2004 includes increases of $7.4 million in labor and benefits expense, $1.8 million in costs related to contract work performed for others, $1.5 million in storm damage repair costs, $1.3 million in tree-trimming and transmission line and pole maintenance expenditures and $1.1 million in maintenance expenses related to the seven-week maintenance shutdown of the Big Stone Plant in 2005. The increase in labor and benefit expenses is due to wage and salary increases averaging 3.6% and increases in pension costs, storm-related overtime pay, performance bonuses and safety awards.

The $0.4 million decrease in property taxes in 2005 compared with 2004 is a result of slightly lower utility property valuations in Minnesota in 2005.

PLASTICS

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

(in thousands)	**2006**	**% change**	2005	% change	2004
Operating revenues	**$163,135**	**3**	$158,548	37	$115,426
Cost of goods sold	**126,374**	**4**	121,245	25	97,126
Operating expenses	**10,239**	**(6)**	10,939	91	5,718
Depreciation and amortization	**2,815**	**12**	2,511	9	2,297
Operating income	**$ 23,707**	**(1)**	$ 23,853	132	$ 10,285

2006 compared with 2005

The $4.6 million increase in plastics operating revenues in 2006 compared with 2005 reflects a 12.6% increase in the price per pound of PVC and polyethylene pipe sold offset by an 8.8% decrease in pounds of pipe sold between the years. The increase in prices reflects the effect of a 13.7% increase in PVC resin costs per pound of PVC pipe shipped between the periods. The decrease in pounds of pipe sold reflects a significant decrease in sales in the third and fourth quarters of 2006 compared with the third and fourth quarters of 2005, reflecting record demand for PVC pipe in the last half of 2005, as sales were affected by concerns over the adequacy of resin supply following the 2005 Gulf Coast hurricanes. The increase in cost of goods sold is a result of higher resin costs. The decrease in plastics segment operating expenses is due to lower selling, general and administrative expenses between the periods. The increase in depreciation and amortization expense is related to capital additions in 2005 and 2006, mainly for production equipment.

2005 compared with 2004

The $43.1 million increase in plastics operating revenues in 2005 compared with 2004 reflects a 31.9% increase in the average sales price per pound of PVC pipe sold combined with a 3.2% increase in pounds of PVC pipe sold between the years. The increase in revenue reflects the effect of rising resin prices and increased customer demand for PVC pipe. Demand accelerated to record levels late in the third quarter of 2005 as substantial resin price increases were announced and concerns developed over the adequacy of resin supply following the 2005 Gulf Coast hurricanes. A majority of U.S. resin production plants are located in the Gulf Coast region. The increase in revenues was partially offset by a $24.1 million increase in cost of goods sold, reflecting a 19.9% increase in the average cost per pound of pipe sold. The average cost per pound of PVC resin increased 16.4% between the periods. The $5.2 million increase in operating expenses between the periods primarily is due to increases in costs directly related to increased sales. The increase in depreciation and amortization expense relates mostly to production equipment purchased in 2004 and 2005.

MANUFACTURING

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

(in thousands)	**2006**	**% change**	2005	% change	2004
Operating revenues	**$311,811**	**28**	$244,311	21	$201,615
Cost of goods sold	**246,649**	**27**	194,264	23	157,802
Operating expenses	**26,508**	**11**	23,872	13	21,098
Depreciation and amortization	**11,076**	**17**	9,447	21	7,828
Operating income	**$ 27,578**	**65**	$ 16,728	12	$ 14,887

2006 compared with 2005

The increase in revenues in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Revenues at DMI Industries, Inc. (DMI), our manufacturer of wind towers, increased $64.0 million (88.4%) as a result of increases in production and sales activity due in part to plant additions, including initial operations at the Ft. Erie, Ontario facility which generated $25.3 million in revenue in 2006, its first year of operations, and continued improvements in productivity and capacity utilization.
- Revenues at ShoreMaster, Inc., our waterfront equipment manufacturer, increased $3.2 million (5.7%) between the years due to price increases driven by higher material costs, especially aluminum and due to the acquisition of Southeast Floating Docks in May 2005.
- Revenues at T.O. Plastics, Inc., our manufacturer of thermoformed plastic and horticultural products, increased $0.7 million (1.9%) between the periods as a result of a 0.9% increase in unit sales combined with a 1.5% increase in revenue per unit sold.
- Revenues at BTD Manufacturing Inc. (BTD), our metal parts stamping and fabrication company, decreased $0.4 million (0.5%) between the periods. However, BTD's operating income increased $3.6 million due, in part, to productivity improvements between the years.

The increase in cost of goods sold in our manufacturing segment in 2006 compared with 2005 relates to the following:

- DMI's cost of goods sold increased $51.5 million between the periods, including increases of $39.6 million in material costs, $9.2 million in labor and benefit costs and $2.7 million in tools and supplies expenditures. The increase in cost of goods sold is directly related to the increase in DMI's production and sales activity and initial operation and start up costs at its Ft. Erie facility.
- Cost of goods sold at ShoreMaster increased $2.4 million between the years as a result of increases in labor, material (especially aluminum) and other direct costs and a full year of operations relating to the acquisition of Southeast Floating Docks, which occurred in May 2005.
- Cost of goods sold at T.O. Plastics increased $2.0 million, reflecting $1.0 million in material cost increases and $0.8 million in increased labor and benefit costs between the years.
- Cost of goods sold at BTD decreased $3.3 million between the periods mainly due to a decrease in labor costs between the years due to a reduction in the number of production employees, a decrease in overtime pay between the periods and a reduction in production hours in December 2006. Productivity gains at BTD were achieved through efforts to better utilize and allocate available labor resources.

The increase in operating expenses in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Operating expenses at DMI increased $2.7 million as a result of increases in labor, professional services and maintenance expenses mainly related to initial operation and start-up costs at the Ft. Erie plant.
- ShoreMaster's operating expenses increased $0.2 million between the years.
- T.O. Plastics' operating expenses increased $0.2 million between the years.
- BTD's operating expenses decreased $0.4 million between the years.

Depreciation expense increased between the years as a result of $21.1 million in capital additions from October 2005 through September 2006 at all four manufacturing companies. Capital additions at DMI's Ft. Erie plant totaled $8.0 million in 2006.

2005 compared with 2004

Revenue increases at the manufacturing companies in 2005 compared with 2004 are due to a combination of factors including increased unit sales, increased sales of higher-priced products, higher prices related to material cost increases and 2005 acquisitions. The increase in cost of goods sold in the manufacturing segment was proportional to the increase in sales revenue resulting in a $6.2 million increase in manufacturing segment gross profits between the periods.

The increase in revenues in our manufacturing segment in 2005 compared with 2004 relates to the following:

- Revenues at DMI increased $23.8 million (48.9%) due to increased production and sales activity. This is in part related to the production tax credits for wind-generated electricity being in place for 2005 as well as improvements in productivity and capacity utilization.
- Revenues at BTD increased $10.2 million (14.9%) mainly as a result of product price increases to cover rising material costs reflected in an 11.8% increase in revenue per unit sold between the periods. The purchase of Performance Tool in January 2005 contributed $3.8 million toward BTD's revenue increase.
- Revenues at ShoreMaster increased $4.9 million (9.5%) due to the acquisitions of Shoreline Industries and Southeast Floating Docks, offset in part by a decline in revenues in its residential and commercial divisions.
- Revenues at T.O. Plastics increased $3.8 million (11.6%) as a result of productivity improvements and higher prices that provided for recovery of increased raw material costs.

The increase in cost of goods sold in our manufacturing segment in 2005 compared with 2004 relates to the following:

- DMI cost of goods sold increased $18.4 million between the periods as a result of increased production and higher raw material costs, subcontractor and labor costs. DMI cost of goods sold also includes a $1.0 million write-down of inventory in the third quarter 2005 for tower sections that had limited use in the wind business due to changes in wind tower design requirements.
- Cost of goods sold at BTD increased $12.1 million as a result of higher raw material and labor costs mainly related to increased production. The purchase of Performance Tool in January 2005 contributed $2.8 million toward BTD's increase in cost of goods sold.
- ShoreMaster's cost of goods sold increased $3.8 million mainly due to the acquisitions of Shoreline Industries and Southeast Floating Docks and increases in material costs.
- T.O. Plastics cost of goods sold increased $2.3 million between the periods as a result of increased material costs.

The increase in operating expenses in our manufacturing segment in 2005 compared with 2004 relates to the following:

- DMI operating expenses increased $1.2 million as a result of a $0.5 million increase in wages, salaries and benefit expenses, a $0.4 million increase in costs associated with changes in plant layout to improve productivity and a $0.2 million increase in repairs and maintenance costs.
- ShoreMaster's operating expenses increased $1.5 million mainly as a result of the acquisitions of Shoreline Industries and Southeast Floating Docks in January and May of 2005.

Depreciation expense increased in 2005 compared with 2004 as a result of 2004 equipment additions and the 2005 manufacturing segment acquisitions.

HEALTH SERVICES

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

(in thousands)	2006	% change	2005	% change	2004
Operating revenues	$135,051	9	$123,991	8	$114,318
Cost of goods sold	104,108	15	90,327	5	85,731
Operating expenses	22,745	3	21,989	25	17,593
Depreciation and amortization	3,660	(9)	4,038	(20)	5,047
Operating income	$ 4,538	(41)	$ 7,637	28	$ 5,947

2006 compared with 2005

The $11.1 million increase in health services operating revenues in 2006 compared with 2005 reflects an $8.0 million increase in imaging revenues combined with a $3.1 million increase in revenues from sales and servicing of diagnostic imaging equipment. On the imaging side of the business, $3.5 million of the $8.0 million increase in revenue came from imaging services where the revenue per scan increased 15.7% between the years while the number of scans completed decreased 8.9%. Revenues from rentals and interim installations of scanning equipment along with providing technical support services for those rental and interim installations increased $4.5 million between the years. The increase in health services revenue was more than offset by the $13.8 million increase in health services cost of goods sold, mainly as a result of increases in costs of equipment purchased for resale, increases in unit rental and sublease costs related to units that were out of service in the first six months of 2006 and increases in labor and other direct costs. The $0.8 million increase in operating expenses is mainly due to increases in property tax expenses. The $0.4 million decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases.

2005 compared with 2004

The $9.7 million increase in health services operating revenues for 2005 compared with 2004 reflects an increase of $13.9 million in scanning and other related service revenues offset by a decline in revenues from equipment sales and service of $4.2 million between the periods. The revenue per scan and the number of scans completed increased 9.6% and 5.9%, respectively. The imaging business added to its fleet of medical imaging equipment in 2005 resulting in an increase in revenue from rentals and interim installations of scanning equipment and related technical support services. The increase in health services revenue was partially offset by increases in cost of goods sold and operating expenses of $9.0 million to support the increases in imaging services activity. The increase in cost of goods sold is mainly related to increased equipment rental costs and increased labor costs partially offset by decreases in materials and maintenance costs. The increase in operating expenses is mainly due to increased payroll and travel expenses and increases in contractual allowances and bad debt expense between the periods and losses on equipment sales in 2005. The decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases. Improved operating efficiencies in the imaging business and service cost reductions initiated in 2004 along with growing scan counts contributed to improved results in the health services segment in 2005.

FOOD INGREDIENT PROCESSING

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

(in thousands)	2006	% change	2005	2004 (19 weeks)
Operating revenues	$ 45,084	17	$ 38,501	$ 14,023
Cost of goods sold	44,233	43	30,930	11,379
Operating expenses	2,920	15	2,533	876
Depreciation and amortization	3,759	11	3,399	1,118
Operating (loss) income	$ (5,828)	(456)	$ 1,639	$ 650

2006 compared with 2005

The $6.6 million increase in food ingredient processing revenues in 2006 compared with 2005 reflects a 15.3% increase in sales price per pound of product combined with a 1.5% increase in pounds of product sold between the years. The food ingredient processing segment has been negatively impacted by raw potato supply shortages in Idaho and Prince Edward Island. Higher than expected raw product costs related to the supply shortages have resulted in operating inefficiencies and a 40.8% increase in the cost per pound of product sold. The increase in operating expenses is due to an increase in selling and administrative expenses between the periods.

Consistent with trends in the industry, operating income for 2006 was less than expected due to raw potato supply shortages, increasing raw material costs and the increasing value of the Canadian dollar relative to the U.S. dollar.

2005 compared with 2004

The increases in revenues, cost of goods sold, operating expenses and depreciation and amortization are due to 2004 results reflecting only 19 weeks of operating activity as a result of the acquisition of IPH in August 2004.

OTHER BUSINESS OPERATIONS

Revenue and expense amounts for 2005 and 2004 have changed from last year's annual report as a result of the sale of OTESCO's natural gas marketing operations in June 2006 and its subsequent reclassification to discontinued operations. The following table summarizes the results of operations for our other business operations segment for the years ended December 31:

(in thousands)	2006	% change	2005	% change	2004
Operating revenues	$147,436	37	$ 107,400	3	$ 104,002
Cost of goods sold	91,806	36	67,711	(2)	69,439
Operating expenses	55,022	5	52,171	23	42,402
Depreciation and amortization	2,917	9	2,666	(9)	2,945
Operating loss	$ (2,309)	85	$ (15,148)	(40)	$ (10,784)

Corporate general and administrative expenses included in the net operating loss from other business operations were $11.9 million, $15.0 million and $10.1 million for the years ended December 31, 2006, 2005 and 2004, respectively. Net operating income (loss) from other business operations before corporate general and administrative expenses was $9.6 million, ($0.1 million) and ($0.7 million) for the years ended December 31, 2006, 2005 and 2004, respectively.

2006 compared with 2005

The increase in operating revenues in our other business operations in 2006 compared with 2005 is due to the following:

- Revenues at Foley Company, a mechanical and prime contractor on industrial projects, increased $33.3 million (106.4%) due to an increase in the volume of work performed between the years.

- Revenues at E.W. Wylie Corporation (Wylie), our flatbed trucking company, increased $4.5 million (14.8%) between the years mainly due to an 8.4% net increase in miles driven by owner-operated and company-operated trucks. Miles driven by owner-operated trucks increased 50.3% while miles driven by company-operated trucks decreased 9.3% between the periods. Wylie's increased revenues also reflect higher rates related to increased fuel costs recovered through fuel surcharges between the periods for both owner-operated and company-operated trucks.
- Revenues at Midwest Construction Services, Inc. (MCS), our electrical design and construction services company, increased $2.3 million (5.2%) between the periods as a result of increased activity on several wind projects in the fourth quarter of 2006.

The increase in cost of goods sold in our other business operations in 2006 compared with 2005 is due to the following:

- Foley Company's cost of goods sold increased $28.3 million mainly in the areas of materials, subcontractor and labor costs as a result of an increase in the volume of work performed between the years.
- Cost of goods sold at MCS decreased $4.2 million mainly due to a reduction in material and labor costs between the periods mostly related to a job completed in 2005 on which large losses were incurred as a result of higher than expected costs.

The increase in operating expenses in the other business operations segment is due to the following:

- Wylie's revenue increase was entirely offset by a $4.5 million increase in operating expenses, including $4.0 million in contractor costs related to higher fuel costs combined with an increase in miles driven by owner-operated trucks between the periods and $0.5 million in increased insurance costs.
- Foley Company's operating expenses increased $0.7 million between the periods as a result of increases in employee benefit costs.
- MCS operating expenses increased $1.0 million between the periods, mainly due to increases in employee benefit costs.
- Other operating expenses decreased $3.3 million as a result of lower corporate costs consisting of lower health insurance plan costs, improved claims experience in our captive insurance company and a gain on the sale of property.

The increase in depreciation and amortization expense in 2006 compared with 2005 is mainly related to equipment purchases at Foley Company in 2005 and 2006.

2005 compared with 2004

The increases in operating revenues and cost of goods sold in our other business operations in 2005 compared with 2004 are due to the following:

- Revenues at MCS increased $16.6 million (61.4%) between the years as a result of an increase in work in progress, which was mostly offset by a $13.7 million increase in cost of goods sold including $4.4 million in increased material and labor costs incurred on a single project that resulted in a significant loss on that project.
- Revenues at Wylie increased $3.7 million (13.7%) in 2005 compared with 2004 due to a 9.7% increase in miles driven by company-operated and owner-operated trucks and a $0.9 million increase in fuel surcharge revenue.
- Revenues at Foley Company decreased $17.2 million (35.4%) in 2005 compared with 2004 due to a decrease in jobs in progress. The decrease in Foley's revenues was mostly offset by a decrease of $15.4 million in material, subcontractor, labor and insurance costs between the periods.

The increase in operating expenses in our other business operations segment in 2005 compared with 2004 relates to the following:

- Wylie's operating expenses increased $3.9 million as a result of higher fuel prices, increased fuel usage and labor costs related to the increase in miles driven and increases in truck leasing costs between the periods.
- Increases in employee health insurance and other employee benefit costs and increases in insurance costs at our captive insurance company contributed $1.9 million to the increase in net losses in this segment.
- MCS reported increased expenses of $0.8 million for wages and benefits, outside contracted services and advertising and promotions in 2005 compared with 2004.

Wylie's depreciation and amortization expenses decreased by $0.3 million between the periods as a result of a 2004 decision to lease rather than buy replacement trucks for their fleet.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS

Other income and deductions decreased by $2.2 million in 2006 compared with 2005. The major item contributing to the decrease was a noncash charge of $3.3 million in 2006 resulting from uncertainty with respect to the capitalized cost of construction funds included in the electric utility's rate base.

CONSOLIDATED INTEREST CHARGES

Interest expense increased $1.0 million in 2006 compared to 2005 primarily as a result of increased interest rates on short-term debt. In 2006, short-term debt interest expense was $2.5 million at an average rate of 5.8% on an average daily balance of $41.9 million, compared with $1.6 million at an average rate of 3.7% on an average daily balance of $42.6 million in 2005.

Interest expense increased $0.3 million in 2005 compared to 2004 primarily as a result of increased interest rates on short-term debt. In 2005, short-term debt interest expense was $1.6 million at an average rate of 3.7% on an average daily balance of $42.6 million, compared with $1.2 million at an average rate of 2.2% on an average daily balance of $57.8 million in 2004.

CONSOLIDATED INCOME TAXES

The 3.2% decrease in income tax expense from continuing operations in 2006 compared to 2005 is due, in part, to a 4.9% decrease in income from continuing operations before income taxes. Our effective tax rate on income from continuing operations was 34.8% for 2006 compared with 34.2% for 2005.

The 61.3% increase in income tax expense from continuing operations in 2005 compared to 2004 is due, in part, to a 41.5% increase in income from continuing operations before income taxes. Our effective tax rate on income from continuing operations was 34.2% for 2005 compared with 30.0% for 2004. The difference in the effective tax rate for 2005 compared to 2004 is a function of the level of fixed deductions and credits in proportion to higher net income before tax in 2005 compared to 2004. See note 15 to consolidated financial statements.

DISCONTINUED OPERATIONS

In 2006, we sold the natural gas marketing operations of OTESCO, our energy services subsidiary. Discontinued operations includes the operating results of OTESCO's natural gas marketing operations for 2006, 2005 and 2004. Discontinued operations also includes an after-tax gain on the sale of OTESCO's natural gas marketing operations of $0.3 million in 2006.

In 2005, we sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Discontinued operations includes the operating results of MIS, SGS and CLC for 2005 and 2004. Discontinued operations also includes an after-tax gain on the sale of MIS of $11.9 million, an after-tax loss on the sale of SGS of $1.7 million and an after-tax loss on the sale of CLC of $0.2 million in 2005.

The following table presents operating revenues, expenses, including interest and other income and deductions, and income taxes, included on a net basis in income from discontinued operations on our 2006, 2005 and 2004 consolidated statements of income.

(in thousands)	**2006**	2005	2004
Operating revenues	**$ 28,234**	$ 80,988	$ 78,027
Expenses	**28,180**	81,601	75,213
Goodwill impairment loss	**—**	1,003	—
Income tax expense (benefit)	**28**	(261)	1,121
Income (loss) from discontinued operations	**$ 26**	$ (1,355)	$ 1,693

The $1.0 million goodwill impairment loss in 2005 relates to the write-off of goodwill at OTESCO related to its natural gas marketing operations in the third quarter of 2005 as a result of a reassessment of its future cash flows in light of rising natural gas prices and greater market volatility in future prices for natural gas.

The following table presents the pre-tax and net-of-tax gains and losses recorded on the sales of OTESCO's natural gas marketing operations in 2006 and MIS, SGS and CLC in 2005.

	2006	2005			
(in thousands)	**OTESCO-gas**	MIS	SGS	CLC	Total
Gain (loss) on sale	**$ 560**	$ 19,025	$ (2,919)	$ (271)	$ 15,835
Income tax (expense) benefit	**(224)**	(7,107)	1,168	108	(5,831)
Net gain (loss) on sale	**$ 336**	$ 11,918	$ (1,751)	$ (163)	$ 10,004

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 unregulated businesses. 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.

2007 EXPECTATIONS

We anticipate 2007 diluted earnings per share from continuing operations to be in a range from *$1.60 to $1.80. Contributing to our earnings* guidance for 2007 are the following items:

- We expect slightly improved performance in our electric segment in 2007.
- We expect our plastics segment's performance to return to more historical levels in 2007 following two strong years in 2005 and 2006.
- We expect continued enhancements in productivity and capacity utilization, strong backlogs and an announced expansion of DMI's Ft. Erie, Ontario facility that will increase the facility's production capacity by 30% to result in increased net income in our manufacturing segment in 2007.
- We expect moderate net income growth in our health services segment in 2007.
- We expect our food ingredient processing business (IPH) to generate net income in the range of $2.0 million to $4.0 million in 2007.
- We expect our other business operations segment to have lower earnings in 2007 compared with 2006 due to an expected return to more normal unallocated corporate cost levels. The construction companies are expected to have a strong 2007 given backlogs at December 31, 2006.

Our outlook for 2007 is dependent on a variety of factors and is subject to the risks and uncertainties discussed under "Risk Factors and Cautionary Statements."

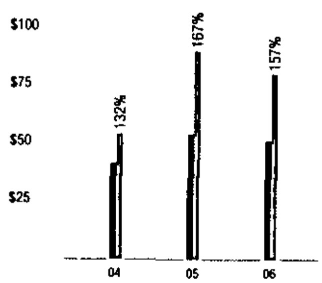
LIQUIDITY

We believe our financial condition is strong and that our cash, other liquid assets, operating cash flows, access to capital markets through our universal shelf registration 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 or debt financing will be required in the period 2007 through 2011 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 short-term and long-term debt ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

We have achieved a high degree of long-term liquidity by maintaining desired capitalization ratios and solid credit ratings, implementing cost-containment programs and investing in projects that provide returns in excess of our weighted average cost of capital.

Cash provided by operating activities from continuing and discontinued operations was $80.2 million in 2006 compared with $95.8 million in 2005. The $15.6 million decrease in cash from operations reflects an increase in cash used for working capital items of $24.4 million and a $3.2 million decrease in net income from continuing operations, offset by a $5.7 million reduction in noncash gains on derivatives, a $3.5 million increase in noncash depreciation expenses and a $3.3 million noncash reduction in allowance for equity funds used during construction. Net cash used for working capital items was $30.4 million in 2006 compared with $6.0 million in 2005. The $30.4 million in cash used for working capital in 2006 reflects increases at DMI of $13.3 million in receivables, $6.9 million in inventory and $17.4 million in costs in excess of billings, offset by an $18.4 million increase in billings in excess of costs related to increased production of wind towers at the West Fargo plant and as a result of

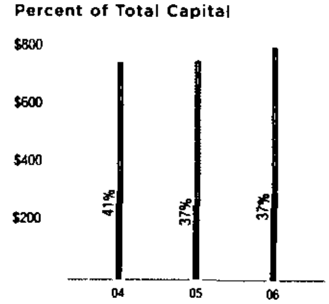
Cash Realization Ratios–Continuing Operations



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

Cash flows from continuing operations
Net income from continuing operations

Interest Bearing Debt as a Percent of Total Capital



Otter Tail has maintained a 37-41% interest-bearing debt to total capital ratio for the past three years. The decrease in IBD to total capitalization from 2004 to 2005 reflects an increase in net income of $20.4 million between the years.

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

starting up a new plant in Ft. Erie, Ontario in 2006. The increase of $13.3 million in receivables at DMI is due to increased sales volumes between the years and a major customer electing different payment terms in the fourth quarter of 2006. Receivables at our construction companies are up $12.8 million as of December 31, 2006 compared to December 31, 2005 as a result of increased construction activity. The increase in working capital items also reflects a $5.7 million increase in inventories at our plastic pipe companies more than offset by a decrease in receivables of $7.9 million as sales declined in the fourth quarter of 2006.

The $37.5 million increase in net cash used in investing activities in 2006 compared with 2005 reflects a $32.2 million decrease in proceeds from the sales of discontinued operations, mainly reflecting proceeds from the sales of MIS, SGS and CLC in 2005, and a $9.5 million increase in capital expenditures. A breakdown of capital expenditures by segment is provided below under "Capital Requirements." We completed no acquisitions in 2006.

Net cash used in financing activities was $13.3 million in 2006 compared with net cash used in financing activities of $62.0 million in 2005. Major uses of cash for financing activities in 2006 were $33.9 million for the payment of dividends on common shares outstanding and $3.3 million for the retirement of long-term debt. Major sources of cash from financing activities in 2006 were $22.9 million from a net increase in short-term borrowings and $2.4 million from the issuance of common stock.

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, 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 annually 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.

Consolidated capital expenditures for the years 2006, 2005 and 2004 were $69.4 million, $60.0 million and $49.5 million, respectively. Estimated capital expenditures for 2007 are $167 million and the total capital expenditures for the five-year period 2007 through 2011 are estimated to be approximately $889 million, which includes $360 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. The breakdown of 2004, 2005 and 2006 actual and 2007 through 2011 estimated capital expenditures by segment is as follows:

(in millions)	2004	2005	2006	2007	2007-2011
Electric	$ 25	$ 30	$ 35	$ 130	$ 776
Plastics	3	4	5	12	19
Manufacturing	13	16	20	19	59
Health services	4	3	5	2	12
Food ingredient processing	4	3	2	3	17
Other business operations	1	4	2	1	6
Total	$ 50	$ 60	$ 69	$ 167	$ 889

The following table summarizes our contractual obligations at December 31, 2006 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	**$ 259**	$ 55	$ 6	$ 93	$ 105
Interest on long-term debt obligations	**130**	15	24	24	67
Operating lease obligations	**154**	41	69	33	11
Capacity and energy requirements	**95**	20	40	11	24
Coal contracts (required minimums)	**80**	17	14	14	35
Postretirement benefit obligations	**49**	4	7	7	31
Other purchase obligations	**38**	38	–	–	–
Total contractual cash obligations	**$ 805**	$ 190	$ 160	$ 182	$ 273

Interest on $10.4 million of variable-rate debt outstanding on December 31, 2006 was projected based on the interest rates applicable to that debt instrument on December 31, 2006.

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, our universal shelf registration, unused lines of credit, strong financial coverages, solid credit ratings, and alternative financing arrangements such as leasing. We have the ability to issue up to $256 million of common stock, preferred stock, debt and certain other securities from time to time under our universal shelf registration statement filed with the Securities and Exchange Commission. Additional equity or debt financing will be required in the period 2007 through 2011 given the expansion plans related to our electric segment to fund the construction of the proposed new Big Stone II generating station at the Big Stone Plant site and a proposed new wind generation project, in the event we decide to refund or retire early any of our presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

On April 26, 2006 we renewed our line of credit with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West and increased the amount available under the line from $100 million to $150 million. The renewed agreement expires on April 26, 2009. The terms of the renewed line of credit are essentially the same as those in place prior to the renewal. However, outstanding letters of credit issued by the company can reduce the amount available for borrowing under the line by up to $30 million and can increase our commitments under the renewed line of credit up to $200 million. Borrowings under the line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. Our bank line of credit is a key source of operating capital and can provide interim financing of working capital and other capital requirements, if needed. This line is an unsecured revolving credit facility available only to support borrowings of our nonelectric operations. Our obligations under this line of credit are guaranteed by a 100%-owned subsidiary that owns substantially all of our nonelectric companies. As of December 31, 2006, $35.0 million of the $150 million line of credit was in use and $18.3 million was restricted from use to cover outstanding letters of credit.

On September 1, 2006 we entered into a separate $25 million line of credit with U.S. Bank National Association. This line of credit creates an unsecured revolving credit facility the electric utility can draw on to support the working capital needs and other capital requirements of its electric operations. This line of credit expires on September 1, 2007. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. This line of credit contains terms that are substantially the same as those under the $150 million line of credit. As of December 31, 2006, $3.9 million of the $25 million line of credit was in use.

In February 2007, we entered into a note purchase agreement with Cascade Investment L.L.C. (Cascade) pursuant to which we agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of our senior notes due November 30, 2017. Cascade is our largest shareholder, owning approximately 8.7% of our outstanding common stock as of December 31, 2006. The notes are expected to be priced based on the 10 year US Treasury Forward rate plus 110 basis points, subject to adjustment in the event certain ratings assigned to our long-term senior unsecured indebtedness are downgraded below specific levels prior to the closing of the note purchase. The terms of the note purchase agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of our $90 million 6.63% senior notes due December 1, 2011. The closing is expected to occur on December 3, 2007 subject to the satisfaction of certain conditions to closing, such as, there has been no event or events having a material adverse effect on the company as a whole, certain senior executives will still be in their roles, there has been no change in control nor impermissible sale of assets, the consolidated debt ratio to earnings before interest, taxes, depreciation and amortization as of September 30, 2007 will be less than 3.5 to 1, certain waivers will have been obtained and certain other customary conditions of closing will have been satisfied.

We have the right to terminate the note purchase agreement by giving at least 30 days' prior written notice to Cascade and paying a termination fee of $1 million. The proceeds of this financing will be used to redeem our $50 million 6.375% senior debentures due December 1, 2007.

Our lines of credit, $90 million 6.63% senior notes and Lombard US Equipment Finance note contain the following covenants: a debt-to-total capitalization ratio not in excess of 60% and an interest and dividend coverage ratio of at least 1.5 to 1. The 6.63% senior notes also require that priority debt not be in excess of 20% of total capitalization. We were in compliance with all of the covenants under our financing agreements as of December 31, 2006.

Our obligations under the 6.63% senior notes are guaranteed by our 100%-owned subsidiary that owns substantially all of our nonelectric companies. Our Grant County and Mercer County pollution control refunding revenue bonds and our 5.625% insured senior notes require that we grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds and notes, a security interest in the assets of the electric utility if the rating on our senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

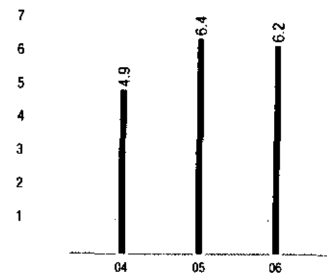
Our securities ratings at December 31, 2006 are:

	Moody's Investors Service	Standard & Poor's
Senior unsecured debt	A3	BBB+
Preferred stock	Baa2	BBB-
Outlook	Stable	Stable

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 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 3.9x for 2006 compared to 4.3x for 2005 and our long-term debt interest coverage ratio before taxes was 6.2x for 2006 compared to 6.4x for 2005. During 2007, we expect these coverage ratios to be consistent with 2006 levels assuming 2007 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 which could result in 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 could restrict our ability to access capital and increase our 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, the 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.

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 plans 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 company's 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.

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 grow our nonelectric businesses could be limited by state law.
Our plans to acquire and grow 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 system that includes a regulated utility company or affiliated nonelectric companies.

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 (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, 2006, we had capitalized $6.1 million in costs related to the planned construction of a second electric generating unit at our Big Stone Plant site. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

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 scheduled to file a rate case in Minnesota on or before October 1, 2007. We are also regulated by the Federal Energy Regulatory Commission. 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.

Recovery of MISO schedule 16 and 17 administrative costs associated with providing electric service to Minnesota customers are currently being deferred pending our next general rate case scheduled to be filed on or before October 1, 2007. If we are not granted recovery of $0.4 million in deferred costs as of December 31, 2006, we could be required to recognize these costs immediately in expense at the time recovery is denied. Also, all MISO-related energy administrative and other costs associated with providing electric service to North Dakota customers have been, and continue to be, recovered under a temporary order from the North Dakota Public Service Commission and are subject to refund if later disallowed.

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 Burlington Northern Santa Fe Railroad 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 the 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 (CO2) emissions, could affect our operating costs and the costs of supplying electricity to our customers.

PLASTICS

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.
We rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors accounted for approximately 99% of our total purchases of PVC resin in 2006 and approximately 97% of our total purchases of PVC resin in 2005. 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, the availability of production tax credits and general economic conditions could affect the revenues and earnings of our manufacturing businesses.
Our manufacturing businesses are subject to risks associated with competition from foreign and domestic manufacturers that have excess capacity, labor advantages and other capabilities that may place downward pressure on margins and profitability. Raw material costs for items such as steel, lumber, concrete, aluminum and resin have increased significantly and may continue to increase. Our manufacturers may not be able to pass on the cost of such increases to their respective customers. 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. We believe the demand for wind towers that we manufacture will depend primarily on the existence of either renewable portfolio standards or a federal production tax credit for wind energy. A federal production tax credit is in place through December 31, 2008. Our wind tower manufacturer and electrical contractor could be adversely affected if the tax credit in not extended or renewed.

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 operations has a dealership and other agreements with Philips Medical from which it derives significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.
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 were terminated within the notice provisions or we were not able to renew such agreements or 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, 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 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, natural gas 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 natural gas 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 32% of its sales are outside the United States and the Canadian plant pays its operating expenses in Canadian dollars.

We currently have $24.2 million of goodwill and a $3.2 million non-amortizable trade name recorded on our balance sheet related to the acquisition of IPH in 2004. If current conditions of low sales prices, high energy and raw material costs, shortage of raw potato supplies and the increased value of the Canadian dollar relative to the U.S. dollar persist and 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 goodwill and nonamortizable intangible assets and a corresponding charge against earnings.

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, 2006 we had limited exposure to market risk associated with interest rates and commodity prices and limited exposure to market risk associated with changes in foreign currency exchange rates. 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 32% of IPH sales are outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of December 31, 2006 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, 2006, 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 electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2006 the electric utility had recognized, on a pretax basis, $203,000 in net unrealized gains 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. Prices are benchmarked to regional hub prices as published in *Megawatt Daily* and forward price curves and indices acquired from a third party price forecasting service. Of the forward energy contracts that are marked to market as of December 31, 2006, all of the forward sales of electricity had offsetting purchases 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, 2006 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, 2006 and the change in our consolidated balance sheet position from December 31, 2005 to December 31, 2006:

(in thousands)	December 31, 2006
Current asset—marked-to-market gain	$ 2,215
Regulatory asset—deferred marked-to-market loss	—
Total assets	2,215
Current liability—marked-to-market loss	(2,012)
Regulatory liability—deferred marked-to-market gain	—
Total liabilities	(2,012)
Net fair value of marked-to-market energy contracts	$ 203

(in thousands)	Year ended December 31, 2006
Fair value at beginning of year	$ 2,916
Amount realized on contracts entered into in 2005 and settled in 2006	(2,090)
Changes in fair value of contracts entered into in 2005	(826)
Net fair value of contracts entered into in 2005 at year end 2006	—
Changes in fair value of contracts entered into in 2006	203
Net fair value at end of year	$ 203

The $203,000 in recognized but unrealized net gain on the forward energy purchases and sales marked to market on December 31, 2006 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2007	2nd Quarter 2007	**Total**
Net gain	$ 159	$ 44	**$ 203**

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, 2006 was $4.3 million. As of December 31, 2006 we had a net credit risk exposure of $7.2 million from 12 counterparties with investment grade credit ratings. We have no exposure at December 31, 2006 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 $7.2 million 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, 2006. 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 increase prices for its finished products to recover increases in fuel costs. In the third quarter of 2006, IPH entered into forward natural gas contracts on the New York Mercantile Exchange market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts are derivatives subject to mark-to-market accounting but they do not qualify for hedge accounting treatment. IPH includes net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition. IPH had $371,000 in marked-to-market losses on forward natural gas contracts outstanding on December 31, 2006, and had recorded $171,000 in net realized losses on contracts that settled in 2006. IPH's forward natural gas swaps marked to market as of December 31, 2006 are scheduled for settlement in the first quarter of 2007.

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, unscheduled power exchanges, MISO electric market residual load adjustments, 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 2007 for our noncontributory funded pension plan is expected to be $5.9 million compared to $5.8 million in 2006. The estimated discount rate used to determine annual benefit cost accruals will be 6.00% in 2007; the discount rate that was used in 2006 was 5.75%. In selecting the discount rate, we use the yield of a fixed income debt security, which has a rating of "Aa" published by a recognized rating agency, along with a bond matching model 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 2006, all other factors being held constant: a 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2006 pension benefit cost by $620,000; a 0.25 increase (or decrease) in the assumed rate of increase in future compensation levels would have increased (or decreased) our 2006 pension benefit cost by $570,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2006 pension benefit cost by $360,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2006 postretirement medical benefit costs by $20,000. 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, 2006 were $284 million. Any expected losses on jobs in progress at year-end 2006 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 and our food ingredient processing company's forward natural gas swap transactions are derivatives subject to mark-to-market accounting under accounting principles generally accepted in the United States. 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. Prices are benchmarked to regional hub prices as published in *Megawatt Daily* and forward price curves and indices acquired from a third party price forecasting service and, as such, are estimates. Of the forward electric energy contracts that are marked to market as of December 31, 2006, 100% of the forward energy purchases for electricity have offsetting sales 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, 2006 are scheduled for settlement prior to June 1, 2007.

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 net recognized 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 2006, $1.3 million of bad debt expense from continuing operations (0.12% of total 2006 revenue of $1.1 billion) was recorded and the allowance for doubtful accounts was $3.0 million (1.8% of trade accounts receivable) as of December 31, 2006. 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 of one percentage point in our consolidated allowance for doubtful accounts based on outstanding trade receivables at December 31, 2006 would result in a $1.5 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. However, 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 2.82% in 2006, 2.74% in 2005 and 2.77% in 2004. 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 current appraised value 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 include reserves for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe the resulting tax reserve balances as of December 31, 2006 reflect the most likely probable expected outcome of these tax matters in accordance with SFAS No. 5, *Accounting for Contingencies*, 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 based on items currently reserved for.

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, 2006 an assessment of the carrying values of our long-lived assets and other intangibles indicated that 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, 2006 an assessment of the carrying values of our goodwill indicated no impairment.

PURCHASE ACCOUNTING

We account 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, *Business Combinations*. 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.

KEY ACCOUNTING PRONOUNCEMENTS

SFAS No. 123(R) (revised 2004), *Share-Based Payment*, issued in December 2004 is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*. Beginning in January 2006, we adopted SFAS No. 123(R) on a modified prospective basis. We are required to record stock-based compensation as an expense on our income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements resulted in recording incremental after-tax compensation expense in 2006 as follows:

- $163,000 for non-vested stock options that were outstanding on December 31, 2005.
- $235,000 for the 15% discount offered under our Employee Stock Purchase Plan.

See additional discussion under Share-based Payments in the footnotes to the consolidated financial statements that follow. For years prior to 2006, we reported our stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123.

In November 2005, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 123(R)-3, *Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards*. We elected to adopt the alternative transition method provided in FSP No. FAS 123(R)-3 for calculating the tax effects of stock-based compensation. The alternative transition method includes simplified methods to determine the beginning balance of the additional paid-in capital (APIC) pool related to the tax effects of stock-based compensation, and to determine the subsequent impact on the APIC pool and the statement of cash flows of the tax effects of stock-based awards that were fully vested and outstanding upon the adoption of SFAS No. 123(R).

FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS 109, *Accounting for Income Taxes*. We will be required to recognize, in our financial statements, the tax effects of a tax position that is "more-likely-than-not" to be sustained on audit based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. FIN No. 48 is effective as of the beginning of the first fiscal year after December 15, 2006, which is January 1, 2007, for our company. Only tax positions that meet the "more-likely-than-not" threshold at that date may be recognized. The cumulative effect of initially applying FIN No. 48 will be recognized as a change in accounting principle as of the end of the period in which FIN No. 48 is adopted. We have assessed the impact of FIN No. 48 on our uncertain tax positions as of January 1, 2007 and determined that it will have no material impact on our consolidated financial statements on adoption.

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 will be 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. We cannot predict what, if any, impact this new standard will have on our consolidated financial statements when the standard becomes effective in 2008.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, was issued by the FASB in September 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 will not change the amount of net periodic benefit expense recognized in an entity's income statement. It is effective for fiscal years ending after December 15, 2006. We determined 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, we 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. Application of this standard had the following effects on our December 31, 2006 consolidated balance sheet:

(in thousands)	2006
Decrease in Executive Survivor and Supplemental Retirement Plan intangible asset	$ (767)
Increase in regulatory assets for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates	36,736
Increase in pension benefit and other postretirement liability	(34,714)
Increase in deferred tax liability	(502)
Decrease in accumulated other comprehensive loss for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates (increase to equity)	(753)

The adoption of this standard did not affect compliance with debt covenants maintained in our financing agreements.

Securities and Exchange Commission Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements,* was issued in September 2006 to address diversity in practice in quantifying financial statement misstatements. SAB No. 108 requires a company to quantify misstatements based on their impact on each of its consolidated financial statements and related disclosures. SAB 108 is effective for our company as of December 31, 2006, allowing a one-time transitional cumulative effect adjustment to retained earnings as of July 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on our consolidated financial statements.

MANAGEMENT'S REPORT REGARDING INTERNAL CONTROLS 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 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 controls over financial reporting, as such term is defined in Exchange Act Rules 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 controls over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework* to conduct the required assessment of the effectiveness of the Company's internal controls 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 Rules 13a-15(f) and 15d-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, 2006 the Company's internal controls over financial reporting are effective based on those criteria.

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

John Erickson
President and Chief Executive Officer

Kevin Moug
Chief Financial Officer and Treasurer
February 19, 2007

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, 2006 and 2005, and the related consolidated statements of income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. We also have audited management's assessment, included in the accompanying Management's Report Regarding Internal Controls Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on these financial statements, an opinion on management's assessment, and an opinion on the effectiveness of 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 audit of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and 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 as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in notes 1 and 4 to the consolidated financial statements, effective December 31, 2006, the Corporation adopted the recognition and disclosure provisions of Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."

Deloitte & Touche LLP

Minneapolis, Minnesota
February 19, 2007

CONSOLIDATED STATEMENTS OF INCOME—FOR THE YEARS ENDED DECEMBER 31

(in thousands, except per-share amounts)	2006	2005	2004
Operating revenues			
Electric	$ 305,703	$ 312,624	$ 266,020
Nonelectric	799,251	669,245	547,016
Total operating revenues	1,104,954	981,869	813,036
Operating expenses			
Production fuel—electric	58,729	55,927	52,056
Purchased power—electric system use	58,281	58,828	40,098
Electric operation and maintenance expenses	103,548	99,904	85,361
Cost of goods sold—nonelectric (excludes depreciation; included below)	611,737	502,407	420,394
Other nonelectric expenses	115,290	109,707	86,037
Depreciation and amortization	49,983	46,458	43,471
Property taxes—electric	9,589	10,043	10,411
Total operating expenses	1,007,157	883,274	737,828
Operating income	97,797	98,595	75,208
Other income and deductions	(440)	1,773	788
Interest charges	19,501	18,459	18,128
Income from continuing operations before income taxes	77,856	81,909	57,868
Income taxes–continuing operations	27,106	28,007	17,366
Net income from continuing operations	50,750	53,902	40,502
Discontinued operations			
Income (loss) from discontinued operations net of taxes of $28 in 2006, ($261) in 2005 and $1,121 in 2004	26	(352)	1,693
Goodwill impairment loss	—	(1,003)	—
Net gain on disposition of discontinued operations net of taxes of $224 in 2006 and $5,831 in 2005	336	10,004	—
Net income from discontinued operations	362	8,649	1,693
Net income	51,112	62,551	42,195
Preferred dividend requirements	736	735	736
Earnings available for common shares	$ 50,376	$ 61,816	$ 41,459
Average number of common shares outstanding—basic	29,394	29,223	26,089
Average number of common shares outstanding—diluted	29,664	29,348	26,207
Basic earnings per share:			
Continuing operations (net of preferred dividend requirements)	$ 1.70	$ 1.82	$ 1.53
Discontinued operations	0.01	0.30	0.06
	$ 1.71	$ 2.12	$ 1.59
Diluted earnings per share:			
Continuing operations (net of preferred dividend requirements)	$ 1.69	$ 1.81	$ 1.52
Discontinued operations	0.01	0.30	0.06
	$ 1.70	$ 2.11	$ 1.58
Dividends per common share	$ 1.15	$ 1.12	$ 1.10

See accompanying notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEETS, DECEMBER 31

(in thousands)	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,791	$ 5,430
Accounts receivable:		
Trade (less allowance for doubtful accounts of $2,964 for 2006 and $3,493 for 2005)	135,011	117,796
Other	10,265	11,790
Inventories	103,002	88,677
Deferred income taxes	8,069	6,871
Accrued utility revenues	23,931	22,892
Costs and estimated earnings in excess of billings	38,384	21,542
Other	9,611	16,476
Assets of discontinued operations	289	13,701
Total current assets	335,353	305,175
Investments and other assets	29,946	33,824
Goodwill—net	98,110	98,110
Other intangibles—net	20,080	21,160
Deferred debits		
Unamortized debt expense and reacquisition premiums	6,133	6,520
Regulatory assets and other deferred debits	50,419	19,616
Total deferred debits	56,552	26,136
Plant		
Electric plant in service	930,689	910,766
Nonelectric operations	239,269	228,548
Total	1,169,958	1,139,314
Less accumulated depreciation and amortization	479,557	459,438
Plant—net of accumulated depreciation and amortization	690,401	679,876
Construction work in progress	28,208	17,215
Net plant	718,609	697,091
Total	$ 1,258,650	$ 1,181,496

See accompanying notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEETS, DECEMBER 31

(in thousands, except per share data)	**2006**	2005
LIABILITIES AND EQUITY		
Current liabilities		
Short-term debt	**$ 38,900**	$ 16,000
Current maturities of long-term debt	**3,125**	3,340
Accounts payable	**120,195**	97,239
Accrued salaries and wages	**28,653**	24,326
Accrued federal and state income taxes	**2,383**	8,449
Other accrued taxes	**11,509**	12,518
Other accrued liabilities	**10,495**	14,124
Liabilities of discontinued operations	**197**	10,983
Total current liabilities	**215,457**	186,979
Pension benefit liability	**44,035**	23,216
Other postretirement benefits liability	**32,254**	26,982
Other noncurrent liabilities	**18,866**	18,683
Commitments (note 9)		
Deferred credits		
Deferred income taxes	**112,740**	113,737
Deferred investment tax credit	**8,181**	9,327
Regulatory liabilities	**63,875**	61,624
Other	**281**	1,500
Total deferred credits	**185,077**	186,188
Capitalization (page 40)		
Long-term debt, net of current maturities	**255,436**	258,260
Class B stock options of subsidiary	**1,255**	1,258
Cumulative preferred shares	**15,500**	15,500
Common shares, par value $5 per share—authorized, 50,000,000 shares; outstanding, 2006—29,521,770 shares; 2005—29,401,223 shares	**147,609**	147,006
Premium on common shares	**99,223**	96,768
Unearned compensation	**—**	(1,720)
Retained earnings	**245,005**	228,515
Accumulated other comprehensive loss	**(1,067)**	(6,139)
Total common equity	**490,770**	464,430
Total capitalization	**762,961**	739,448
Total	**$ 1,258,650**	$ 1,181,496

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

(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, 2003	**25,723,814**	**$ 128,619**	**$ 26,515**	**$ (3,313)**	**$ 186,495**	**$ (4,429)**	**$ 333,887**
Common stock issuances, net of expenses	3,266,266	16,332	63,373	(566)			79,139
Common stock retirements	(13,161)	(66)	(283)				(349)
Amortization of unearned compensation—stock awards				1,302			1,302
Comprehensive income:							
Net income					42,195		42,195
Unrealized loss on marketable equity securities						(14)	(14)
Foreign currency exchange translation						1,014	1,014
Minimum pension liability adjustment						3,039	3,039
Total comprehensive income							46,234
Tax benefit for exercise of stock options			92				92
Valuation of stock options of subsidiary acquired in 2004			(1,832)				(1,832)
Cumulative preferred dividends					(735)		(735)
Common dividends					(28,528)		(28,528)
Balance, December 31, 2004	**28,976,919**	**$ 144,885**	**$ 87,865**	**$ (2,577)**	**$ 199,427**	**$ (390)**	**$ 429,210**
Common stock issuances, net of expenses	456,211	2,281	8,483	(529)			10,235
Common stock retirements	(31,907)	(160)	(756)				(916)
Amortization of unearned compensation—stock awards				1,386			1,386
Comprehensive income:							
Net income					62,551		62,551
Unrealized loss on marketable equity securities						(23)	(23)
Foreign currency exchange translation						437	437
Minimum pension liability adjustment						(6,163)	(6,163)
Total comprehensive income							56,802
Tax benefit for exercise of stock options			596				596
Stock incentive plan performance award accrual			943				943
Premium on purchase of stock for employee purchase plan			(363)				(363)
Cumulative preferred dividends					(735)		(735)
Common dividends					(32,728)		(32,728)
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 loss on marketable equity securities						56	56
Foreign currency exchange translation						6	6
SFAS No. 87 minimum pension liability adjustment						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 compensation award accruals			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**

(a) Accumulated other comprehensive loss on December 31, 2006 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)
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)

See accompanying notes to consolidated financial statements.

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

(in thousands)	2006	2005	2004
Cash flows from operating activities			
Net income	$ 51,112	$ 62,551	$ 42,195
Adjustments to reconcile net income to net cash provided by operating activities:			
Net gain on sale of discontinued operations	(336)	(10,004)	—
(Income) loss from discontinued operations	(26)	1,355	(1,693)
Depreciation and amortization	49,983	46,458	43,471
Deferred investment tax credit	(1,146)	(1,150)	(1,152)
Deferred income taxes	(1,258)	(9,223)	3,950
Change in deferred debits and other assets	(38,499)	8,865	(1,641)
Discretionary contribution to pension plan	(4,000)	(4,000)	(4,000)
Change in noncurrent liabilities and deferred credits	45,340	1,321	2,110
Allowance for equity (other) funds used during construction	2,529	(723)	(716)
Change in derivatives net of regulatory deferral	3,083	(2,615)	1,755
Stock compensation expense	2,404	2,388	87
Other—net	418	1,118	1,343
Cash (used for) provided by current assets and current liabilities:			
Change in receivables	(15,713)	(9,715)	(7,357)
Change in inventories	(14,345)	(12,500)	(6,894)
Change in other current assets	(17,409)	(13,908)	(15,360)
Change in payables and other current liabilities	23,022	32,682	(647)
Change in interest and income taxes payable	(5,952)	(2,552)	(1,041)
Net cash provided by continuing operations	79,207	90,348	54,410
Net cash provided by discontinued operations	1,039	5,452	1,891
Net cash provided by operating activities	80,246	95,800	56,301
Cash flows from investing activities			
Capital expenditures	(69,448)	(59,969)	(49,484)
Proceeds from disposal of noncurrent assets	5,233	4,193	5,844
Acquisitions—net of cash acquired	—	(11,223)	(69,069)
(Increases) decreases in other investments	(3,326)	4,171	(5,099)
Net cash used in investing activities—continuing operations	(67,541)	(62,828)	(117,808)
Net proceeds from sale of discontinued operations	1,960	34,185	—
Net cash provided by (used in) investing activities—discontinued operations	—	602	(1,310)
Net cash used in investing activities	(65,581)	(28,041)	(119,118)
Cash flows from financing activities			
Change in checks written in excess of cash	(11)	(3,329)	3,458
Net short-term borrowings (repayments)	22,900	(23,950)	9,950
Proceeds from issuance of common stock, net of issuance expenses	2,444	9,690	78,780
Payments for retirement of common stock and Class B stock of subsidiary	(463)	(939)	(349)
Proceeds from issuance of long-term debt	149	368	4,186
Debt issuance expenses	(458)	(140)	(121)
Payments for retirement of long-term debt	(3,287)	(7,232)	(9,061)
Dividends paid	(34,621)	(33,463)	(29,263)
Net cash (used in) provided by financing activities—continuing operations	(13,347)	(58,995)	57,580
Net cash used in financing activities—discontinued operations	—	(2,996)	(1,679)
Net cash (used in) provided by financing activities	(13,347)	(61,991)	55,901
Effect of foreign exchange rate fluctuations on cash	43	(338)	(794)
Net change in cash and cash equivalents	1,361	5,430	(7,710)
Cash and cash equivalents at beginning of year—continuing operations	5,430	—	7,710
Cash and cash equivalents at end of year—continuing operations	$ 6,791	$ 5,430	$ —
Supplemental disclosures of cash flow information			
Cash paid during the year from continuing operations for:			
Interest (net of amount capitalized)	$ 18,456	$ 17,637	$ 16,410
Income taxes	$ 35,061	$ 39,548	$ 16,211
Cash paid during the year from discontinued operations for:			
Interest	$ 91	$ 119	$ 144
Income taxes	$ 423	$ 323	$ 833

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION, DECEMBER 31

(in thousands, except share data)	2006	2005
Long-term debt		
Senior notes 6.63%, due December 1, 2011	**$ 90,000**	$ 90,000
Senior debentures 6.375%, due December 1, 2007	**50,000**	50,000
Insured senior notes 5.625%, due October 1, 2017	**40,000**	40,000
Senior notes 6.80%, due October 1, 2032	**25,000**	25,000
Mercer County, North Dakota pollution control refunding revenue bonds 4.85%, due September 1, 2022	**20,735**	20,735
Pollution control refunding revenue bonds, variable, 4.31% at December 31, 2006, due December 1, 2012	**10,400**	10,400
Lombard US Equipment Finance note 6.76%, due October 2, 2010	**9,314**	11,643
Grant County, South Dakota pollution control refunding revenue bonds 4.65%, due September 1, 2017	**5,185**	5,185
Obligations of Varistar Corporation—various up to 9.33% at December 31, 2006	**8,424**	9,235
Total	**259,058**	262,198
Less:		
Current maturities	**3,125**	3,340
Unamortized debt discount	**497**	598
Total long-term debt—continuing operations	**255,436**	258,260
Class B stock options of subsidiary	**1,255**	1,258
Cumulative preferred shares—without par value (stated and liquidating value $100 a share)—authorized 1,500,000 shares;		
Series outstanding:		
$3.60, 60,000 shares	**6,000**	6,000
$4.40, 25,000 shares	**2,500**	2,500
$4.65, 30,000 shares	**3,000**	3,000
$6.75, 40,000 shares	**4,000**	4,000
Total preferred	**15,500**	15,500
Cumulative preference shares—without par value, authorized 1,000,000 shares; outstanding: none		
Total common shareholders' equity	**490,770**	464,430
Total capitalization	**$ 762,961**	$ 739,448

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*. These amounts are not material.

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 (AFUDC). AFUDC, a noncash item, is included in utility construction work in progress. The amount of AFUDC capitalized was $952,000 for 2006, $913,000 for 2005 and $949,000 for 2004. In 2006, the Company recorded a noncash charge to other income and deductions of $3.3 million resulting from uncertainty with respect to the capitalized cost of construction funds included in the electric utility's rate base. 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 2.82% in 2006, 2.74% in 2005 and 2.77% in 2004. 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 appraised value 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). 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, 2006 and 2005 consolidated balance sheets:

(in thousands)	Big Stone Plant	Coyote Station
December 31, 2006		
Electric plant in service	**$ 124,965**	**$ 147,319**
Accumulated depreciation	**(75,872)**	**(80,336)**
Net plant	**$ 49,093**	**$ 66,983**
December 31, 2005		
Electric plant in service	$ 124,852	$ 146,405
Accumulated depreciation	(71,824)	(77,909)
Net plant	$ 53,028	$ 68,496

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 when the temporary differences reverse. The Company amortizes the investment tax credit over the estimated lives of the related property.

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 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 and the energy services company's swap transactions, 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.

Electric customers' meters are read and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment—under which the rates are adjusted to reflect changes in average cost of fuels and purchased power—and a surcharge for recovery of conservation-related expenses. Revenue is accrued for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the fuel clause adjustment.

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 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, 2006**	December 31, 2005
Costs incurred on uncompleted contracts	**$ 257,370**	$ 194,076
Less billings to date	**(284,273)**	(203,862)
Plus estimated earnings recognized	**35,955**	22,834
	$ 9,052	$ 13,048

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, 2006**	December 31, 2005
Costs and estimated earnings in excess of billings on uncompleted contracts	**$ 38,384**	$ 21,542
Billings in excess of costs and estimated earnings on uncompleted contracts	**(29,332)**	(8,494)
	$ 9,052	$ 13,048

FOREIGN CURRENCY TRANSLATION

The functional currency for the operations of the Canadian subsidiary of Idaho Pacific Holdings, Inc. (IPH) is the Canadian dollar. The translation of Canadian currency into U.S. dollars 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 in the equity section of the Company's consolidated balance sheet. The functional currency for the Canadian subsidiary of DMI Industries, Inc., formed in November 2005, 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 Canadian dollars. Foreign currency transaction gains or losses related to balance sheet adjustments of Canadian dollar liabilities to U.S. dollar equivalents or realized gains and losses on settlement of those liabilities will be included in other nonelectric expenses on the Company's consolidated statements of income.

PRE-PRODUCTION COSTS

The Company incurs costs related to the design and development of molds, dies and tools as part of the manufacturing process. The Company accounts for these costs under EITF Issue 99-5, *Accounting for Pre-production Costs Related to Long-Term Supply Arrangements*. The Company capitalizes the costs related to the design and development of molds, dies and tools used to produce products under a long-term supply arrangement, some of which are owned by the Company. The balance of pre-production costs deferred on the balance sheet was $2,251,000 as of December 31, 2006 and $2,074,000 as of December 31, 2005. These costs are amortized over a three-year period and evaluated at least annually, or more often when events indicate an impairment could exist.

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, unscheduled power exchanges and residual load adjustments related to purchase and sales transactions processed through the Midwest Independent Transmission System Operator (MISO) that are pending settlement, 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.

ADJUSTMENTS AND RECLASSIFICATIONS

The Company's consolidated statements of income and consolidated statements of cash flows for the years ended December 31, 2005 and 2004, and its December 31, 2005 consolidated balance sheet reflect the reclassifications of the operating results, assets and liabilities of the natural gas marketing operations of OTESCO, the Company's energy services company, to discontinued operations as a result of the sale of these operations in June 2006. The reclassifications had no impact on the Company's total consolidated net income or cash flows for the years ended December 31, 2005 and 2004 or on its total consolidated assets or liabilities as of December 31, 2005.

CASH EQUIVALENTS

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

INVESTMENTS

The following table provides a breakdown of the Company's investments at December 31, 2006 and 2005:

(in thousands)	**December 31, 2006**	December 31, 2005
Cost method:		
Economic development loan pools	**$ 569**	$ 742
Other	**1,518**	1,913
Equity method:		
Affordable housing partnerships	**2,228**	2,980
Marketable securities classified as available-for-sale	**4,640**	3,067
Total investments	**$ 8,955**	$ 8,702

The Company has investments in eleven limited partnerships that invest in tax-credit-qualifying affordable-housing projects that provided tax credits of $839,000 in 2006, $1,324,000 in 2005 and $1,418,000 in 2004. The Company owns a majority interest in eight of the eleven limited partnerships with a total investment of $2,155,000. FASB Interpretation (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 an equity method basis due to immateriality. Consolidating these entities would have represented less than 0.6% of total assets, 0.1% of total revenues and (0.2%) of operating income for the Company as of, and for the year ended, December 31, 2006 and would have no impact on the Company's 2006 consolidated net income as the amount is the same under both the equity and full consolidation methods.

The Company's marketable securities classified as available-for-sale are held for insurance reserve purposes and are reflected at their market values on December 31, 2006, with $18,000 in unrealized gains included in Accumulated other comprehensive income in the equity section of the Company's December 31, 2006 consolidated balance sheet. See further discussion under note 13.

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, 2006**	December 31, 2005
Finished goods	**$ 46,477**	$ 38,928
Work in process	**5,663**	7,146
Raw material, fuel and supplies	**50,862**	42,603
Total inventories	**$ 103,002**	$ 88,677

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 an impairment could exist. 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*.

Goodwill did not change in 2006 as the Company did not acquire any businesses or make any adjustments to goodwill during the period. The following table shows goodwill balances by segment:

(in thousands)	**December 31, 2006**	December 31, 2005
Plastics	**$ 19,302**	$ 19,302
Manufacturing	**15,698**	15,698
Health services	**24,328**	24,328
Food ingredient processing	**24,240**	24,240
Other business operations	**14,542**	14,542
Total	**$ 98,110**	$ 98,110

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

2006 *(in thousands)*	Gross carrying amount	Accumulated amortization	Net carrying amount
Amortized intangible assets:			
Covenants not to compete	**$ 2,198**	**$ 1,813**	**$ 385**
Customer relationships	**10,574**	**1,016**	**9,558**
Other intangible assets including contracts	**2,083**	**1,291**	**792**
Total	**$14,855**	**$ 4,120**	**$10,735**
Nonamortized intangible assets:			
Brand/trade name	**$ 9,345**	**$ —**	**$ 9,345**
2005 *(in thousands)*			
Amortized intangible assets:			
Covenants not to compete	$ 2,338	$ 1,620	$ 718
Customer relationships	10,575	583	9,992
Other intangible assets including contracts	2,785	1,680	1,105
Total	$15,698	$ 3,883	$11,815
Nonamortized intangible assets:			
Brand/trade name	$ 9,345	$ —	$ 9,345

Intangible assets with finite lives are being amortized over average lives that vary from one to 25 years. The amortization expense for these intangible assets was $1,079,000 for 2006, $1,077,000 for 2005 and $701,000 for 2004. The estimated annual amortization expense for these intangible assets for the next five years is: $872,000 for 2007, $727,000 for 2008, $636,000 for 2009, $507,000 for 2010 and $457,000 for 2011.

NEW ACCOUNTING STANDARDS

SFAS No. 123(R) (revised 2004), *Share-Based Payment*, issued in December 2004 is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*. Beginning in January 2006, the Company adopted SFAS No. 123(R) on a modified prospective basis. The Company is required to record stock-based compensation as an expense on its income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements resulted in recording incremental after-tax compensation expense in 2006 as follows:

- $163,000, net-of-tax, in 2006 for non-vested stock options that were outstanding on December 31, 2005.
- $235,000 in 2006 for the 15% discount offered under our Employee Stock Purchase Plan.

See note 7 for additional discussion. For years prior to 2006, the Company reported its stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123.

In November 2005, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 123(R)-3, *Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards*. We elected to adopt the alternative transition method provided in FSP No. FAS 123(R)-3 for calculating the tax effects of stock-based compensation. The alternative transition method includes simplified methods to determine the beginning balance of the additional paid-in capital (APIC) pool related to the tax effects of stock-based compensation, and to determine the subsequent impact on the APIC pool and the statement of cash flows of the tax effects of stock-based awards that were fully vested and outstanding upon the adoption of SFAS No. 123(R).

FIN No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS 109, *Accounting for Income Taxes*. The Company will be required to recognize, in its financial statements, the tax effects of a tax position that is "more-likely-than-not" to be sustained on audit based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. FIN No. 48 is effective as of the beginning of the first fiscal year after December 15, 2006, which is January 1, 2007 for the Company. Only tax positions that meet the "more-likely-than-not" threshold at that date may be recognized. The cumulative effect of initially applying FIN No. 48 will be recognized as a change in accounting principle as of the end of the period in which FIN No. 48 is adopted. The Company has assessed the impact of FIN No. 48 on its uncertain tax positions as of January 1, 2007 and determined that FIN No. 48 will have no material impact on the Company's consolidated financial statements on adoption.

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 will be 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 Company cannot predict what, if any, impact this new standard will have on its consolidated financial statements when the standard becomes effective in 2008.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, was issued by the FASB in September 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 will not change the amount of net periodic benefit expense recognized in an entity's income statement. It is effective for fiscal years ending after December 15, 2006. The Company determined 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. Application of this standard had the following effects on the Company's December 31, 2006 consolidated balance sheet:

(in thousands)	**2006**
Decrease in Executive Survivor and Supplemental Retirement Plan intangible asset	**$ (767)**
Increase in regulatory assets for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates	**36,736**
Increase in pension benefit and other postretirement liability	**(34,714)**
Increase in deferred tax liability	**(502)**
Decrease in accumulated other comprehensive loss for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates (increase to equity)	**(753)**

The adoption of this standard did not affect compliance with debt covenants maintained in the Company's financing agreements.

Securities and Exchange Commission Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*, was issued in September 2006 to address diversity in practice in quantifying financial statement misstatements. SAB No. 108 requires a company to quantify misstatements based on their impact on each of its consolidated financial statements and related disclosures. SAB 108 is effective for the Company as of December 31, 2006, allowing a one-time transitional cumulative effect adjustment to retained earnings as of July 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on the Company's consolidated financial statements.

2. BUSINESS COMBINATIONS, DISPOSITIONS AND SEGMENT INFORMATION

The Company acquired no new businesses in 2006.

On January 3, 2005 the Company's wholly-owned subsidiary, BTD Manufacturing, Inc. (BTD), acquired the assets of Performance Tool & Die, Inc. (Performance Tool) of Lakeville, Minnesota, for $4.1 million in cash. Performance Tool specializes in manufacturing mid to large progressive dies for customers throughout the Midwest, East and West Coasts, and the southern United States. Performance Tool's revenues for the year ended December 31, 2004 were $4.1 million. This acquisition provided expanded growth opportunities for both BTD and Performance Tool.

Also, on January 3, 2005 the Company's wholly-owned subsidiary, ShoreMaster, Inc. (ShoreMaster), acquired the common stock of Shoreline Industries, Inc. (Shoreline), of Pine River, Minnesota, for $2.4 million in cash. Shoreline is a manufacturer of boatlift motors and other accessories for lifts and docks with sales throughout the United States, but primarily in Minnesota and Wisconsin. Shoreline's revenues for the year ended December 31, 2004 were $2.1 million. The acquisition of Shoreline secures a source of components and expands potential markets for ShoreMaster products.

On May 31, 2005 ShoreMaster acquired the assets of Southeast Floating Docks, Inc., of St. Augustine, Florida for $4.0 million in cash. Southeast Floating Docks is a leading manufacturer of concrete floating dock systems for marinas. They have designed custom floating systems and conducted installations mainly in the southeast United States and the Caribbean. Southeast Floating Docks had revenues of $4.5 million in 2004. This acquisition enables ShoreMaster to offer a wider range of products to its customers and expands its geographic reach in the Southeast region of the United States.

Below are condensed balance sheets, at the date of the business combinations, disclosing the allocation of the purchase price assigned to each major asset and liability category of the acquired companies.

(in thousands)	Performance Tool	Shoreline Industries	Southeast Floating Docks
Assets			
Current assets	$ 748	$ 464	$ 2,437
Plant	1,396	260	415
Deferred income taxes	22	—	—
Goodwill	1,772	1,442	2,804
Other intangible assets	800	557	1,150
Total assets	$ 4,738	$ 2,723	$ 6,806
Liabilities			
Current liabilities	$ 324	$ 86	$ 318
Deferred revenue	—	—	2,520
Deferred income taxes	—	235	—
Long-term debt	298	—	—
Total liabilities	$ 622	$ 321	$ 2,838
Cash paid	$ 4,116	$ 2,402	$ 3,968

Goodwill and other intangible assets related to the Performance Tool acquisition are deductible for income tax purposes over 15 years. Other intangible assets related to the Performance Tool acquisition includes $239,000 for a nonamortizable trade name and $561,000 in other intangible assets being amortized over 3 to 15 years for book purposes. Goodwill and other intangible assets related to the Shoreline acquisition are not deductible for income tax purposes, except for a $171,000 noncompete agreement being amortized over 15 years for income tax purposes. Other intangible assets related to the Shoreline acquisition includes $149,000 for a nonamortizable brand name and $408,000 in other intangible assets being amortized over 5 to 20 years for book purposes. Goodwill and other intangible assets related to the Southeast Floating Docks acquisition are deductible for income tax purposes over 15 years. Other intangible assets related to the Southeast Floating Docks acquisition includes $1.0 million for a nonamortizable brand name.

On August 18, 2004 the Company acquired all of the outstanding common stock of IPH, located in Ririe, Idaho, a leading processor of dehydrated potato products in North America, for $68.2 million in cash. An additional $6.0 million in cash was placed in escrow to pay off earn-out contingencies if IPH achieved certain financial targets for the period from August 1, 2004 through July 31, 2005. The financial targets were not achieved and the $6.0 million of funds held in escrow were returned to the Company in the third quarter of 2005. The results of operations of IPH have been included in the Company's consolidated results of operations since the date of acquisition and are included in the food ingredient processing segment. This acquisition added a new platform to the Company's diversified portfolio of businesses. IPH is headquartered in Ririe, Idaho, where its largest processing facility is located. It also has potato dehydration plants in Souris, Prince Edward Island, Canada, and Center, Colorado. IPH supplies products for use in foods such as mashed potatoes, snacks and baked goods. Its customers include many of the largest domestic and international food manufacturers in the snack food, foodservice and baking industries. IPH exports potato products to Europe, the Middle East, the Pacific Rim and Central America. IPH had revenues of $43.5 million for its fiscal year ended July 31, 2004.

Below is a condensed balance sheet of IPH disclosing the final allocation of the purchase price assigned to each major asset and liability category.

(in thousands)	IPH
Assets	
Current assets	$ 17,740
Plant	35,296
Goodwill	24,240
Other intangible assets	13,200
Total assets	$ 90,476
Liabilities	
Current liabilities	$ 5,893
Deferred income taxes	12,408
Long-term debt	2,140
Class B common stock options	1,832
Total liabilities	$ 22,273
Cash paid	$ 68,203

Goodwill and other intangible assets related to the IPH acquisition are not deductible for income tax purposes. Other intangible assets related to the IPH acquisition includes $10.0 million for customer relationships being amortized over 25 years and a $3.2 million nonamortizable trade name.

All of the acquisitions described above were accounted for using the purchase method of accounting. The pro forma effect of these acquisitions on 2005 and 2004 revenues, net income or earnings per share was not significant.

In June 2006, OTESCO, the Company's energy services company, sold its gas marketing operations. In 2005, the Company sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Prior to disposition, OTESCO's gas marketing operations and MIS were included in the other business operations segment and SGS and CLC were included in the manufacturing segment. See note 16 on discontinued operations for further discussion.

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 operations have been the Company's primary business since incorporation. The Company's electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation.

All of the businesses in the following segments are owned by a wholly-owned subsidiary of the Company.

Plastics consists of businesses producing polyvinyl chloride and polyethylene pipe in the Upper Midwest and Southwest regions of the United States.

Manufacturing consists of businesses in the following manufacturing activities: production of waterfront equipment, wind towers, material and handling trays and horticultural containers, contract machining, and metal parts stamping and fabrication. These businesses have manufacturing facilities in Minnesota, North Dakota, South Carolina, Missouri, California, Florida 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, Europe, the Middle East, the Pacific Rim and Central America.

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, as well as the portion of corporate general and administrative expenses that are not allocated to other segments. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and 6 Canadian provinces.

No 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:

	2006	2005	2004
United States of America	**97.2%**	97.8%	96.9%
Canada	**1.3%**	1.1%	2.2%
All other countries	**1.5%**	1.1%	0.9%

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 2006, 2005 and 2004 is presented in the following table.

(in thousands)	2006	2005	2004
Operating revenue			
Electric	**$ 306,014**	$ 312,985	$ 266,385
Plastics	**163,135**	158,548	115,426
Manufacturing	**311,811**	244,311	201,615
Health services	**135,051**	123,991	114,318
Food ingredient processing	**45,084**	38,501	14,023
Other business operations	**147,436**	107,400	104,002
Intersegment eliminations	**(3,577)**	(3,867)	(2,733)
Total	**$1,104,954**	$ 981,869	$ 813,036
Depreciation and amortization			
Electric	**$ 25,756**	$ 24,397	$ 24,236
Plastics	**2,815**	2,511	2,297
Manufacturing	**11,076**	9,447	7,828
Health services	**3,660**	4,038	5,047
Food ingredient processing	**3,759**	3,399	1,118
Other business operations	**2,917**	2,666	2,945
Total	**$ 49,983**	$ 46,458	$ 43,471
Interest charges			
Electric	**$ 10,315**	$ 10,271	$ 10,109
Plastics	**814**	1,080	834
Manufacturing	**6,550**	4,516	2,480
Health services	**910**	822	925
Food ingredient processing	**481**	165	13
Other business operations	**431**	1,605	3,767
Total	**$ 19,501**	$ 18,459	$ 18,128
Income before income taxes			
Electric	**$ 38,802**	$ 55,984	$ 45,234
Plastics	**22,959**	22,803	9,453
Manufacturing	**21,148**	12,242	12,543
Health services	**3,909**	6,875	5,075
Food ingredient processing	**(6,325)**	1,482	618
Other business operations*	**(2,637)**	(17,477)	(15,055)
Total	**$ 77,856**	$ 81,909	$ 57,868
Earnings available for common shares			
Electric	**$ 23,445**	$ 36,566	$ 30,799
Plastics	**14,326**	13,936	5,657
Manufacturing	**13,171**	7,589	7,563
Health services	**2,230**	4,007	2,951
Food ingredient processing	**(4,115)**	329	351
Other business operations	**957**	(9,260)	(7,555)
Total	**$ 50,014**	$ 53,167	$ 39,766
Capital expenditures			
Electric	**$ 35,207**	$ 30,479	$ 25,368
Plastics	**5,504**	3,636	2,544
Manufacturing	**20,048**	16,112	13,163
Health services	**4,720**	3,095	3,919
Food ingredient processing	**1,762**	2,952	3,528
Other business operations	**2,207**	3,695	962
Total	**$ 69,448**	$ 59,969	$ 49,484
Identifiable assets			
Electric	**$ 689,653**	$ 654,175	$ 634,433
Plastics	**80,666**	76,573	67,574
Manufacturing	**219,336**	177,969	150,800
Health services	**66,126**	67,066	66,506
Food ingredient processing	**94,462**	96,023	92,392
Other business operations	**108,118**	95,989	81,851
Discontinued operations	**289**	13,701	40,592
Total	**$1,258,650**	$1,181,496	$1,134,148

**Income before income taxes of other business operations includes unallocated corporate expenses of $11,303,000, $16,650,000 and $13,855,000 for the years ended December 31, 2006, 2005 and 2004, respectively.*

3. RATE MATTERS

MINNESOTA

In September 2004, the Company provided a letter to the Minnesota Public Utilities Commission (MPUC) summarizing issues and conclusions of an internal investigation the Company had completed related to claims of allegedly improper regulatory filings brought to the Company's attention by certain individuals. On November 30, 2004 the electric utility filed a report with the MPUC responding to these claims. In 2005, the Energy Division of the Department of Commerce (DOC), the Residential Utilities Division of the Office of Attorney General and the claimants filed comments in response to the report, to which the Company filed reply comments. 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. The Company received comments on its filings from the DOC and the claimants and filed reply comments in August 2006.

The DOC recommended accepting the revised Regulatory Compliance Plan and the chart of accounts definition. The electric utility filed supplemental comments related to its Corporate Allocation Manual in November 2006. The electric utility also agreed to file a general rate case in Minnesota on or before October 1, 2007. At a MPUC meeting on January 25, 2007 all remaining open issues were resolved. The MPUC accepted the Company's compliance filing with minor changes, agreed to allow the electric utility to calculate corporate cost allocations as proposed, determined not to conduct any further review at this time and required the Company to include all of its short-term debt in its AFUDC calculations. The Company has agreed to provide the MPUC the results of the current FERC Operational Audit when available, compare the corporate allocation method to a commonly accepted methodology in its next rate case, and provide the results of the Company's investigation relating to a 2007 hotline complaint. The Company recorded a noncash charge to other income and deductions of $3.3 million in 2006 related to uncertainty with respect to the capitalized cost of construction funds included in the electric utility's rate base.

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

On July 24, 2006 the DOC and Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG) filed comments supporting the idea of convening a technical conference on the recovery of MISO costs among other things. On August 7, 2006 the MPUC received reply comments from the RUD-OAG and collectively from the utilities. On October 31, 2006 the MPUC convened a technical conference at which the parties provided a summary of the Joint Report. On November 6, 2006 the utilities filed supplemental comments. This matter returned to the MPUC on November 7, 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 this order. The MPUC 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. Each utility may continue deferring schedule 16 and 17 costs without interest until the earlier of March 1, 2009 or the utility's next electric rate case. By March 1, 2009 the utility shall begin amortizing the balance of the deferred Day 2 costs through March 1, 2012 unless and until the utility has a rate case addressing the utility's proposal for recovering the balance. In its next rate case a utility may seek to recover schedule 16 and 17 costs at an appropriate level of base rate recovery. The utility may not increase rates to recover MISO administrative costs unless the costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. However, a utility may seek to recover schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a rate case, subject to final MPUC approval. As a result of the December 20, 2006 order, the utility will refund $446,000 to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007 and will defer that amount and additional amounts related to MISO schedule 16 and 17 costs incurred subsequent to December 31, 2006 until it is allowed recovery of those costs in its next rate case or in interim rates. The electric utility expects to file its next electric rate case on or before October 1, 2007.

NORTH DAKOTA

In September 2004, a letter was provided to the North Dakota Public Service Commission (NDPSC) summarizing issues and conclusions of an internal investigation completed by the Company as it related to claims of allegedly improper regulatory filings brought to the Company's attention by certain individuals. The NDPSC did not open a formal docket, but its staff reviewed the issues. The Company responded to various data requests and worked with staff and the NDPSC to resolve issues raised by the internal investigation. In an order issued in May 2006, the NDPSC stated that in the opinion of staff, the impact of the issues reviewed was not significant enough to cause a change in the results of the Company's performance-based ratemaking plan in place from 2001 through 2005.

In February 2005, the utility filed with the NDPSC a petition 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. The NDPSC has taken no further action regarding this filing.

FEDERAL

On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time revenue sufficiency guarantee (RSG) charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's 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 compliance filing. On October 26, 2006 the FERC issued an order on rehearing, 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 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.

The Division of Operation Audits of the FERC Office of Market Oversight and Investigations (OMOI) commenced an audit of the electric utility's transmission practices in 2005. The purpose of the audit is to determine whether and how the electric utility's transmission practices are in compliance with the FERC's applicable rules and regulations and tariff requirements and whether and how the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the electric utility's off-system sales. The Division of Operation Audits of the OMOI has not issued an audit report. The Company cannot predict if the results of the audit will have any impact on the Company's consolidated financial statements.

The Comprehensive Energy Policy Act of 2005 (the 2005 Energy Act) signed into law in August 2005, will substantially affect the regulation of energy companies, including the electric utility. The 2005 Energy Act amends federal energy laws and provides the FERC with new oversight responsibilities. Among the important changes to be implemented as a result of this legislation are the following:

- The Public Utility Holding Company Act of 1935 (PUHCA) was repealed effective February 8, 2006. PUHCA significantly restricted mergers and acquisitions in the electric utility sector.
- The FERC will appoint and oversee an electric reliability organization to establish and enforce mandatory reliability rules regarding the interstate electric transmission system. It is expected that the electric reliability organization will be approved and begin operation by mid-year 2006.
- The FERC will establish incentives for transmission companies, such as performance-based rates, recovery of costs to comply with reliability rules and accelerated depreciation for investments in transmission infrastructure.
- Federal support will be available for certain clean coal power initiatives, nuclear power projects and renewable energy technologies.

The implementation of the 2005 Energy Act requires proceedings at the state level and the development of regulations by the FERC and the Department of Energy, as well as other federal agencies. The Company cannot predict when these proceedings and regulations will commence or be finalized. The Company is still studying the legislation and its effect and cannot predict with certainty the impact on its electric operations.

4. REGULATORY ASSETS AND LIABILITIES

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

(in thousands)	December 31, 2006	December 31, 2005
Regulatory assets:		
Unrecognized transition obligation, prior service costs and actuarial losses on pension and other postretirement benefits	**$ 36,736**	$ —
Deferred income taxes	**11,712**	16,724
Accrued cost-of-energy revenue	**10,735**	10,400
Reacquisition premiums	**2,694**	2,995
Deferred conservation program costs	**1,036**	1,064
MISO schedule 16 and 17 deferred administrative costs	**541**	—
Accumulated ARO accretion/depreciation adjustment	**249**	209
Plant acquisition costs	**151**	196
Deferred marked-to-market losses	**—**	1,423
Total regulatory assets	**$ 63,854**	$ 33,011
Regulatory liabilities:		
Accumulated reserve for estimated removal costs	**$ 58,496**	$ 52,582
Deferred income taxes	**5,228**	5,961
Deferred marked-to-market gains	**—**	2,925
Gain on sale of division office building	**151**	156
Total regulatory liabilities	**$ 63,875**	$ 61,624
Net regulatory liability position	**$ 21**	$ 28,613

The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs 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*, adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates. 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*. Accrued cost-of-energy revenue included in Accrued utility revenues will be recovered over the next nine months. Reacquisition premiums included in Unamortized debt expense and reacquisition premiums are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 15.6 years. Deferred conservation program costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. MISO schedule 16 and 17 deferred administrative costs were excluded from recovery through the FCA in Minnesota in a December 2006 order issued by the MPUC. The MPUC ordered the Company to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and recovery of those costs through rates established in the Company's next rate case scheduled to be filed on or before October 1, 2007. The accumulated reserve for estimated removal costs is reduced for actual removal costs incurred. Plant acquisition costs will be amortized over the next 3.4 years. The remaining regulatory assets and liabilities are being recovered from, or 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 ENERGY 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 $25,965,000 in 2006, $46,397,000 in 2005 and $27,228,000 in 2004 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts and, in 2006 and 2005, 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)	**2006**	2005	2004
Wholesale sales—company-owned generation	**$ 23,130**	$ 24,799	$ 17,970
Revenue from settled contracts at market prices	**385,978**	474,882	134,715
Market cost of settled contracts	**(383,594)**	(457,728)	(128,685)
Net margins on settled contracts at market	**2,384**	17,154	6,030
Marked-to-market gains on settled contracts	**20,950**	11,118	12,663
Marked-to-market losses on settled contracts	**(20,702)**	(9,590)	(9,736)
Net marked-to-market gain on settled contracts	**248**	1,528	2,927
Unrealized marked-to-market gains on open contracts	**2,215**	5,678	514
Unrealized marked-to-market losses on open contracts	**(2,012)**	(2,762)	(213)
Net unrealized marked-to-market gain on open contracts	**203**	2,916	301
Wholesale electric revenue	**$ 25,965**	$ 46,397	$ 27,228

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, 2006**	December 31, 2005
Current asset—marked-to-market gain	**$ 2,215**	$ 8,603
Regulatory asset—deferred marked-to-market loss	**—**	1,423
Total assets	**2,215**	10,026
Current liability—marked-to-market loss	**(2,012)**	(4,185)
Regulatory liability—deferred marked-to-market gain	**—**	(2,925)
Total liabilities	**(2,012)**	(7,110)
Net fair value of marked-to-market energy contracts	**$ 203**	$ 2,916

(in thousands)	Year ended December 31, 2006
Fair value at beginning of year	$ 2,916
Amount realized on contracts entered into in 2005 and settled in 2006	(2,090)
Changes in fair value of contracts entered into in 2005	(826)
Net fair value of contracts entered into in 2005 at year end 2006	—
Changes in fair value of contracts entered into in 2006	203
Net fair value at end of year	$ 203

The $203,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market as of December 31, 2006 is expected to be realized on physical settlement or settled by an offsetting agreement with the counterparty to the original contract as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2007	2nd Quarter 2007	Total
Net gain	$ 159	$ 44	$ 203

All of the forward energy purchase contracts that are marked to market as of December 31, 2006 are offset by forward energy sales contracts in terms of volumes and delivery periods.

NATURAL GAS CONTRACTS

In the third quarter of 2006, IPH entered into forward natural gas swaps on the New York Mercantile Exchange market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts are derivatives subject to mark-to-market accounting but they do not qualify for hedge accounting treatment as cash flow hedges because the changes in the NYMEX prices do not correspond closely enough to changes in natural gas prices at the locations of physical delivery. Therefore, IPH includes net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition.

Cost of goods sold in the food ingredient processing segment includes $542,000 in losses in 2006, of which $171,000 was realized, related to IPH's forward natural gas contracts on NYMEX as a result of declining natural gas prices in 2006. The net fair value of contracts held as of December 31, 2006 was ($371,000). IPH's forward natural gas swaps marked to market as of December 31, 2006 are scheduled for settlement in the first quarter of 2007.

6. COMMON SHARES AND EARNINGS PER SHARE

In 2006, the Company issued 107,458 common shares as a result of stock option exercises, 2,209 common shares and 19,800 restricted common shares as directors' compensation and 7,450 common shares for restricted stock units that were granted and vested in 2006. The Company retired 16,370 common shares for tax withholding purposes in connection with the vesting of restricted common shares in 2006.

STOCK INCENTIVE PLAN

Under the 1999 Stock Incentive Plan (Incentive Plan) a total of 2,600,000 common shares were authorized for granting stock awards. The 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. On April 10, 2006 the Company's shareholders approved amendments to the Incentive Plan increasing the number of common shares available under the Incentive Plan from 2,600,000 common shares to 3,600,000 common shares, extending the term of the Incentive Plan from December 13, 2008 to December 13, 2013 and making certain other changes to the terms of the Incentive Plan.

EMPLOYEE STOCK PURCHASE PLAN

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. On April 10, 2006 the Company's shareholders approved an amendment to the Purchase Plan increasing the number of common shares available under the Purchase Plan from 400,000 common shares to 900,000 common shares, of which 449,842 were still available for purchase as of December 31, 2006. 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, 53,258 common shares were purchased in the open market in 2006, 69,401 common shares were purchased in the open market in 2005 and 66,958 common shares were issued in 2004. 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. From June 1999 through December 2003, common shares needed for the Plan were purchased in the open market. From January through October 2004 new shares were issued for this Plan. Starting in November 2004 the Company began purchasing common shares in the open market. Through December 31, 2006, 944,507 common shares had been issued to meet the requirements of the Plan.

SHAREHOLDER RIGHTS PLAN

On January 27, 1997 the Company's Board of Directors declared a dividend of one preferred share purchase right (Right) for each outstanding common share held of record as of February 15, 1997. One Right was also issued with respect to each common share issued after February 15, 1997. The Rights expired pursuant to their terms on January 27, 2007.

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. Currently, the Company intends to purchase shares on the open market for stock performance awards earned.

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, 2006, 2005 and 2004:

Year	Options Outstanding	Range of Exercise Prices
2006	210,250	$29.74-$31.34
2005	237,624	$28.66-$31.34
2004	1,067,900	$26.25-$31.34

7. SHARE-BASED PAYMENTS

On January 1, 2006 the Company adopted the accounting provisions of SFAS No. 123(R) (revised 2004), *Share-Based Payment*, on a modified prospective basis. SFAS No. 123(R) is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*. Under SFAS No. 123(R), the Company records stock-based compensation as an expense on its income statement over the period earned based on the estimated fair value of the stock or options awarded on their grant date. The Company elected the modified prospective method of adopting SFAS No. 123(R), under which prior periods are not retroactively revised. The valuation provisions of SFAS No. 123(R) apply to awards granted after the effective date. Estimated stock-based compensation expense for awards granted prior to the effective date but that remain nonvested on the effective date will be recognized over the remaining service period using the compensation cost estimated for the SFAS No. 123 pro forma disclosures. Additionally, the adoption of SFAS No. 123(R) resulted in the reclassification of $798,000 in credits related to outstanding restricted share-based compensation from equity on the Company's consolidated balance sheet to a liability on January 1, 2006 because of income tax withholding provisions in the share-based award agreements. The adoption of SFAS 123(R) also resulted in the elimination of Unearned compensation from the equity section of the Company's consolidated balance sheet on January 1, 2006 by netting the account balance of $1,720,000 against Premium on common shares.

As of December 31, 2006 the total remaining unrecognized amount of compensation expense related to stock-based compensation was approximately $3.3 million (before income taxes), which will be amortized over a weighted-average period of 2.0 years.

The Company has six share-based payment programs. The effect of SFAS No. 123(R) accounting on each of these programs is explained in the following paragraphs.

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 123(R), the Company is required to record compensation expense related to the 15% discount which was not required under APB No. 25. The 15% discount resulted in compensation expense of $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. Of the options granted, 1,999,975 had vested or were forfeited and 41,525 were not vested as of December 31, 2006. The exercise price of the options granted has been the average market price of the Company's common stock on the grant date. These options were not compensatory under APB No. 25 accounting rules. 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 is 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 is being recognized on a straight-line basis as compensation expense over the remaining vesting period of the nonvested options, which, for nonvested options outstanding on January 1, 2006 will be from January 1, 2006 through April 30, 2007. Accordingly, the Company recorded compensation expense of $271,000 in 2006 related to nonvested options issued under the Incentive Plan.

Had compensation costs for the stock options issued been determined based on estimated fair value at the award dates, as prescribed by SFAS No. 123, the Company's net income for 2005 and 2004 would have decreased as presented in the table below:

(in thousands, except per share amounts)	2005	2004
Net income		
As reported	$ 62,551	$ 42,195
Total stock-based employee compensation expense determined under fair value-based method for all awards net of related tax effects	(640)	(1,087)
Pro forma	$ 61,911	$ 41,108
Basic earnings per share		
As reported	$ 2.12	$ 1.59
Pro forma	$ 2.09	$ 1.55
Diluted earnings per share		
As reported	$ 2.11	$ 1.58
Pro forma	$ 2.08	$ 1.54

No options were granted in 2006. The fair values of the options granted in 2005 and 2004 were estimated using the Black-Scholes option-pricing model under the following assumptions:

	2005	2004
Risk-free interest rate	4.3%	3.9%
Expected lives	7 years	7 years
Expected volatility	25.4%	25.7%
Dividend yield	4.4%	4.0%

The following table summarizes information about options outstanding as of December 31, 2006:

	Options outstanding			Options exercisable	
Range of exercise prices	Outstanding as of 12/31/06	Weighted-average remaining contractual life (yrs)	Weighted-average exercise price	Exercisable as of 12/31/06	Weighted-average exercise price
$18.80-$21.94	251,873	2.8	$ 19.50	251,873	$ 19.48
$21.95-$25.07	56,350	8.3	$ 24.93	56,350	$ 24.93
$25.08-$28.21	566,765	5.0	$ 26.52	525,240	$ 26.42
$28.22-$31.34	216,250	5.2	$ 31.19	216,250	$ 31.17

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 APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the four-year vesting period of the restricted shares based on the market value of the Company's common stock on the grant date. Under the modified prospective application of SFAS No. 123(R) accounting requirements, compensation expense related to nonvested restricted shares outstanding will be recorded based on the estimated fair value of the restricted shares on their grant dates. On April 9, 2006 the Compensation Committee of the Company's Board of Directors granted 19,800 shares of restricted stock to the directors under the Incentive Plan. The restricted shares vest ratably over a four-year vesting period.

Presented below is a summary of the stock options activity:

Stock Option Activity	2006		2005		2004	
	Options	**Average exercise price**	Options	Average exercise price	Options	Average exercise price
Outstanding, beginning of year	**1,237,164**	**$ 25.58**	1,508,277	$ 25.35	1,531,125	$ 25.16
Granted	**—**	**—**	74,900	24.93	72,400	26.50
Exercised	**107,458**	**22.88**	257,948	22.90	51,468	19.83
Forfeited	**38,468**	**28.60**	88,065	28.79	43,780	27.37
Outstanding, year end	**1,091,238**	**25.74**	1,237,164	25.58	1,508,277	25.35
Exercisable, year end	**1,049,713**	**25.69**	1,095,272	25.16	1,111,681	24.27
Cash received for options exercised	**$ 2,458,000**		$ 5,911,000		$ 1,022,000	
Fair value of options granted during year	**none granted**		$ 4.76		$ 5.27	

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

	2006		2005		2004	
	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	**27,000**	**$ 26.32**	22,600	$ 27.61	18,450	$ 28.74
Granted	**19,800**	**$ 28.24**	11,700	$ 24.93	10,800	$ 26.49
Vested	**14,025**	**$ 26.82**	7,300	$ 28.09	6,650	$ 28.94
Forfeited	**—**		—		—	
Nonvested, end of year	**32,775**	**$ 27.27**	27,000	$ 26.32	22,600	$ 27.61
Compensation expense recognized		**$ 401,000**		$ 261,000		$ 219,000
Fair value of shares vested in year		**$ 376,000**		$ 205,057		$ 192,000

RESTRICTED STOCK GRANTED TO EMPLOYEES

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the vesting periods of the restricted shares based on the market value of the Company's common stock on the grant date. Because of income tax withholding provisions in the restricted stock award agreements related to restricted stock granted to employees, the value of these grants is considered variable, which, under SFAS No. 123(R), will require 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 will be 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 under this program will be based on the average market value of the Company's common stock on the reporting date; $31.47 on December 31, 2006.

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. In 2005 and 2004, under APB No. 25, the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the intrinsic value of the restricted stock grants. The equity account, unearned compensation, was credited when compensation expense was recorded related to these shares under APB No. 25 accounting. 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 will be reversed and credited to the Premium on common shares equity account as the shares vest.

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

	2006		2005		2004	
	Shares	Weighted average reporting date fair value	Shares	Weighted average reporting date fair value	Shares	Weighted average reporting date fair value
Nonvested, beginning of year	**72,974**	**$ 28.91**	103,340	$ 25.31	131,800	$ 27.16
Granted	**—**		9,000	$ 26.31	10,540	$ 26.57
Vested	**41,308**	**$ 28.98**	39,126	$ 25.08	39,000	$ 26.40
Forfeited	**—**		240		—	
Nonvested, end of year	**31,666**	**$ 31.47**	72,974	$ 28.91	103,340	$ 25.31
Compensation expense recognized		**$ 815,000**		$ 1,118,000		$ 1,083,000
Fair value of shares vested in year		**$ 1,197,000**		$ 981,000		$ 1,030,000

RESTRICTED STOCK UNITS GRANTED TO EMPLOYEES

On April 9, 2006 the Compensation Committee of the Company's Board of Directors granted 47,425 restricted stock units at a weighted average grant-date fair value of $25.41 per unit to key employees under the Incentive Plan payable in common shares. Each unit is automatically converted into one share of common stock on vesting. Vesting occurs from April 10, 2006 through April 8, 2010, with a weighted average contractual term of stock units outstanding as of December 31, 2006 of 2.6 years. The fair values of the restricted stock units granted in April 2006 were determined by using a Monte Carlo valuation method.

Presented below is a summary of the status of employees' restricted stock unit awards for the year ended December 31, 2006:

	Restricted Stock Units	Aggregate grant-date fair value
Outstanding, January 1, 2006	—	$ —
Granted	47,425	1,205,000
Converted	7,450	220,000
Forfeited	1,360	33,000
Outstanding, December, 2006	38,615	$ 952,000
Compensation expense recognized in 2006		$ 427,000

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 APB No. 25 accounting, these awards were valued based on the average market price of the underlying shares of the Company's common stock on the award grant date, multiplied by the estimated probable number of shares to be awarded at the end of the performance measurement period with compensation expenses recorded ratably over the related three-year measurement period. Compensation expense recognized was adjusted at each reporting date subsequent to the grant date of the awards for the difference between the market value of the underlying shares on their grant date and the market value of the underlying shares on the reporting date. Under the modified prospective application of SFAS No.123(R) accounting requirements, the amount of compensation expense that will be recorded subsequent to January 1, 2006 related to awards granted in 2004 and 2005 and outstanding on December 31, 2006 is based on the estimated grant-date fair value of the awards as determined under the Black-Scholes option pricing model.

On April 9, 2006 the Compensation Committee of the Company's Board of Directors granted stock performance awards to the Company's executive officers under the Incentive Plan. Under these awards, the Company's executive officers could earn up to an aggregate of 88,050 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance period of January 1, 2006 through December 31, 2008. The aggregate target share award is 58,700 shares. Actual payment may range from zero to 150 percent of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. The amount of compensation expense that will be recorded related to awards granted in April 2006 and outstanding on December 31, 2006 is based on the estimated grant-date fair value of the awards as determined under a Monte Carlo valuation method.

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 amounts expensed for 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, 2006	2005	2004
2004-2006	70,500	23,500	$ 23.90	$ 187,000	$ 490,000	–
2005-2007	75,150	50,872	$ 22.10	375,000	453,000	–
2006-2008	88,050	58,700	$ 25.95	508,000	–	–
Total	233,700	133,072		$1,070,000	$ 943,000	–

A total of 23,500 shares were earned for the 2004-2006 performance period based on the Company's ranking in the EEI Index for total shareholder return during the performance period.

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, 2006.

9. COMMITMENTS AND CONTINGENCIES

At December 31, 2006 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $29,232,000. For capacity and energy requirements, the electric utility has agreements extending through 2011 at annual costs of approximately $20,485,000 in 2007, $20,089,000 in 2008, $20,051,000 in 2009, $8,499,000 in 2010 and $2,688,000 in 2011.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2007 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $80,515,000 or to make payments in lieu thereof, under these contracts. The fuel clause adjustment mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

IPH has commitments of approximately $8,800,000 for the purchase of a portion of its 2007 raw potato supply requirements.

The amounts of future operating lease payments are as follows:

(in thousands)	Electric	Nonelectric	Total
2007	$ 2,075	$ 38,787	$ 40,862
2008	1,475	34,692	36,167
2009	1,475	31,149	32,624
2010	1,475	23,058	24,533
2011	1,430	7,534	8,964
Later years	9,931	1,262	11,193
Total	$ 17,861	$ 136,482	$ 154,343

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 $44,254,000, $37,798,000 and $28,601,000 for 2006, 2005 and 2004, respectively.

The Company occasionally 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, 2006 will not be material.

10. SHORT-TERM AND LONG-TERM BORROWINGS

SHORT-TERM DEBT

As of December 31, 2006 the Company had $38.9 million in short-term debt outstanding at a weighted average interest rate of 5.7%. As of December 31, 2005 the Company had $16 million in short-term debt outstanding at an interest rate of 4.8%. The average interest rate paid on short-term debt was 5.8% in 2006 and 3.7% in 2005.

On April 26, 2006 the Company renewed its line of credit with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West and increased the amount available under the line from $100 million to $150 million. The renewed agreement expires on April 26, 2009. The terms of the renewed line of credit are essentially the same as those in place prior to the renewal. However, outstanding letters of credit issued by the Company can reduce the amount available for borrowing under the line by up to $30 million and can increase its commitments under the renewed line of credit up to $200 million. Borrowings under the line of credit bear interest at LIBOR plus 0.4%. This line is an unsecured revolving credit facility available to support borrowings of the Company's nonelectric operations. The Company's obligations under this line of credit are guaranteed by a 100%-owned subsidiary that owns substantially all of the Company's nonelectric companies. As of December 31, 2006, $35.0 million of the $150 million line of credit was in use and $18.3 million was restricted from use to cover outstanding letters of credit.

On September 1, 2006 the Company entered into a separate $25 million line of credit with U.S. Bank National Association. This line of credit creates an unsecured revolving credit facility the Company can draw on to support the working capital needs and other capital requirements of the Company's electric operations. This line of credit expires on September 1, 2007. Borrowings under the line of credit bear interest at LIBOR plus 0.4%. The line of credit contains terms that are substantially the same as those under the $150 million line of credit. As of December 31, 2006, $3.9 million of the $25 million line of credit was in use.

The interest rates under these lines of credit are subject to adjustment in the event of a change in ratings on the Company's senior unsecured debt, up to LIBOR plus 1.0% if the ratings on the Company's senior unsecured debt fall below BBB- (Standard & Poor's) and below Baa3 (Moody's). The Company's bank lines of credit are a key source of operating capital and can provide interim financing of working capital and other capital requirements, if needed.

LONG-TERM DEBT

The Company has the ability to issue up to $256 million of common shares, cumulative preferred shares, debt and certain other securities from time to time under its universal shelf registration statement filed with the Securities and Exchange Commission on June 4, 2004 and declared effective on August 30, 2004. The Company issued no long-term debt under its universal shelf registration in 2006 or 2005.

On September 24, 2003 the Company borrowed $16.3 million under a loan agreement with Lombard US Equipment Finance Corporation in the form of an unsecured note. The terms of the note require quarterly principal payments in the amount of $582,143 commencing in January 2004 with a final installment due on October 2, 2010. The terms of the note were renegotiated in 2006 and the variable interest rate of three-month LIBOR plus 1.43% on the unpaid principal balance was replaced with a fixed rate of 6.76% that will be in effect until the note is fully repaid. Interest payments are due quarterly. The covenants associated with the note are consistent with existing credit facilities. There are no rating triggers associated with this note.

The Company's obligations under the 6.63% senior notes are guaranteed by its 100%-owned subsidiary that owns substantially all of the Company's nonelectric companies. The Company's Grant County and Mercer County pollution control refunding revenue bonds and its 5.625% insured senior notes require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds and notes, a security interest in the assets of the electric utility if the rating on the Company's senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

In February 2007, the Company entered into a 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 its senior notes due November 30, 2017. Cascade is the Company's largest shareholder, owning approximately 8.7% of the Company's outstanding common stock as of December 31, 2006. The notes are expected to be priced based on the 10 year US Treasury Forward rate plus 110 basis points, subject to adjustment in the event certain ratings assigned to the Company's long-term senior unsecured indebtedness are downgraded below specific levels prior to the closing of the note purchase. The terms of the 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 closing is expected to occur on December 3, 2007 subject to the satisfaction of certain conditions to closing, such as, there has been no event or events having a material adverse effect on the Company as a whole, certain senior executives will still be in their roles, there has been no change in control nor impermissible sale of assets, the consolidated debt ratio to earnings before interest, taxes, depreciation and amortization as of September 30, 2007 will be less than 3.5 to 1, certain waivers will have been obtained and certain other customary conditions of closing will have been satisfied.

The Company has the right to terminate the note purchase agreement by giving at least 30 days' prior written notice to Cascade and paying a termination fee of $1 million. The proceeds of this financing will be used to redeem the Company's $50 million 6.375% senior debentures due December 1, 2007.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2006 for each of the next five years are $54,909,000 for 2007, $3,017,000 for 2008, $2,917,000 for 2009, $2,600,000 for 2010 and $90,114,000 for 2011.

COVENANTS

The Company's lines of credit, $90 million 6.63% senior notes and Lombard US Equipment Finance note contain the following covenants: a debt-to-total capitalization ratio not in excess of 60% and an interest and dividend coverage ratio of at least 1.5 to 1. The 6.63% senior notes also require that priority debt not be in excess of 20% of total capitalization. The Company was in compliance with all of the covenants under its financing agreements as of December 31, 2006.

11. CUMULATIVE PREFERRED SHARES AND CLASS B STOCK OPTIONS OF SUBSIDIARY

CUMULATIVE PREFERRED SHARES

All four series of cumulative preferred shares are redeemable at the option of the Company. As of December 31, 2006 the call price by series is:

Series outstanding	Call price
$3.60, 60,000 shares	$ 102.25
$4.40, 25,000 shares	$ 102.00
$4.65, 30,000 shares	$ 101.50
$6.75, 40,000 shares	$ 102.3625

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 1,112 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 2005, options for 357 IPH

Class B common shares were exercised and the Class B common shares were redeemed by IPH 181 days after issuance.

In 2006, IPH granted 305 additional options to purchase IPH Class B Common Stock to five employees at an exercise price of $2,085.88 per option. The options vested immediately on issuance. On the date the options were granted the value of a share of IPH Class B common stock was estimated to be $1,041.71. Therefore, the grant-date fair value of the options was $0 and no expense or liability was recorded related to these options under SFAS No. 123(R). Also in 2006, 2 options were forfeited. As of December 31, 2006 there were 1,058 options outstanding with a combined exercise price of $952,000, of which 753 options were "in-the-money" with a combined exercise price of $316,000.

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.

Effective July 1, 2005 the Company remeasured its pension and other postretirement benefit plan obligations using the RP-2000 Combined Healthy Mortality table in place of the 1983 Group Annuity Mortality table (GAM '83) it used to measure its obligations and determine its annual costs under these plans in January 2005. The reason for the remeasurement was to update the mortality table to more accurately reflect current life expectancies of current employees and retirees included in the plans. Generally accepted accounting principles require that all assumptions used to measure plan obligations and determine annual plan costs be revised as of a remeasurement date. The following actuarial assumptions were updated as of the July 1, 2005 remeasurement date:

Key assumptions and data	January 1, 2005 through June 30, 2005	July 1, 2005 through December 31, 2005
Discount rate	6.00%	5.25%
Long-term rate of return on plan assets	8.50%	8.50%
Social Security wage base	4.00%	3.50%
Rate of inflation	3.00%	2.50%
Rate of withdrawal	1% per year through age 54	2% per year through age 54
Mortality table	GAM '83	RP-2000 projected to 2006
Market value of assets—beginning of period	$141,685,000	$142,547,832

Remeasuring the Company's pension and other postretirement benefit plan obligations as of July 1, 2005 under the revised assumptions had the effect of increasing the Company's 2005 projected pension plan costs by $1,364,000, increasing its 2005 projected Executive Survivor and Supplemental Retirement Plan costs by $123,000 and increasing its 2005 projected costs for postretirement benefits other than pensions by $137,000.

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 Company's policy is to fund pension costs accrued. All past service costs have been provided for.

The pension plan has a trustee who is responsible for pension payments to retirees. Four investment managers are responsible for managing the plan's assets. An independent actuary performs 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)	**2006**	2005	2004
Service cost—benefit earned during the period	**$ 5,057**	$ 4,695	$ 4,063
Interest cost on projected benefit obligation	**10,435**	9,721	9,458
Expected return on assets	**(12,288)**	(12,071)	(12,438)
Amortization of prior-service cost	**742**	726	897
Amortization of net actuarial loss	**1,844**	1,364	—
Net periodic pension cost	**$ 5,790**	$ 4,435	$ 1,980

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

(in thousands)	**2006**	2005
Prepaid pension cost	**$ —**	$ 9,795
Current liability	**—**	—
Noncurrent liability	**(19,252)**	—
Additional minimum liability	**—**	(13,380)
Net amount recognized	**$ (19,252)**	$ (3,585)

Net amount recognized as of December 31:

(in thousands)	**2006**	2005
Regulatory assets:		
Unrecognized prior service cost	**$ (4,748)**	$ —
Unrecognized actuarial loss	**(21,771)**	—
Accumulated other comprehensive loss	**(738)**	(7,757)
Prepaid pension cost	**8,005**	9,795
Intangible asset	**—**	(5,623)
Net amount recognized	**$ (19,252)**	$ (3,585)

Change in regulatory assets and accumulated comprehensive loss due to SFAS No. 158:

(in thousands)	**2006**
Increase in regulatory assets:	
Unrecognized actuarial loss	**$ 21,771**
Unrecognized prior service cost	**4,748**
Increase in accumulated other comprehensive loss:	
Unrecognized actuarial loss:	**606**
Unrecognized prior service cost	**132**
Total change	**$ 27,257**

Funded status as of December 31:

(in thousands)	**2006**	2005
Fair value of plan assets	**$ 167,508**	$ 146,982
Projected benefit obligation	**(186,760)**	(181,587)
Funded status	**$ (19,252)**	$ (34,605)
Accumulated benefit obligation	**$ (153,816)**	$(150,567)

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, 2006:

(in thousands)	**2006**	2005
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	**$ 146,982**	$ 141,685
Actual return on plan assets	**24,856**	9,864
Discretionary company contributions	**4,000**	4,000
Benefit payments	**(8,330)**	(8,567)
Fair value of plan assets at December 31	**$ 167,508**	$ 146,982
Estimated asset return	**17.24%**	7.08%
Reconciliation of projected benefit obligation:		
Projected benefit obligation at January 1	**$ 181,587**	$ 166,190
Service cost	**5,057**	4,695
Interest cost	**10,435**	9,721
Benefit payments	**(8,330)**	(8,567)
Plan amendments	**—**	222
Actuarial (gain) loss	**(1,989)**	9,326
Projected benefit obligation at December 31	**$ 186,760**	$ 181,587
Reconciliation of prepaid pension cost:		
Prepaid pension cost at January 1	**$ 9,795**	$ 10,230
Net periodic pension cost	**(5,790)**	(4,335)
Discretionary company contributions	**4,000**	4,000
Prepaid pension cost at December 31	**$ 8,005**	$ 9,795

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

	2006	2005
Discount rate	**6.00%**	5.75%
Rate of increase in future compensation level	**3.75%**	3.75%

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

	2006	2005
Discount rate (2005 is remeasurement composite rate)	**5.75%**	5.625%
Long-term rate of return on plan assets	**8.50%**	8.50%
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 gain 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 2007 net periodic pension cost is 8.50%.

Measurement dates:	**2006**	2005
Net periodic pension cost	**January 1, 2006**	January 1, 2005 & July 1, 2005
End of year benefit obligations	**January 1, 2006 projected to December 31, 2006**	January 1, 2005 projected to December 31, 2005
Market value of assets	***December 31, 2006***	*December 31, 2005*

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 2007 are:

(in thousands)	**2007**
Decrease in regulatory assets:	
Amortization of unrecognized actuarial loss	$ 1,751
Amortization of unrecognized prior service cost	722
Decrease in accumulated other comprehensive loss:	
Amortization of unrecognized actuarial loss	49
Amortization of unrecognized prior service cost	20
Total estimated amortization	$ 2,542

Cash flows: The Company is not required to make a contribution to the pension plan in 2007 but can contribute up to $79 million before September 15, 2007 and deduct it for the 2006 plan year.

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

(in thousands)			Years		
2007	2008	2009	2010	2011	2012–2016
$ 8,735	$ 8,901	$ 9,072	$ 9,248	$ 9,644	$ 56,411

The Company's pension plan asset allocations at December 31, 2006 and 2005, by asset category are as follows:

Asset Allocation	**2006**	2005
Large capitalization equity securities	**49.3%**	51.2%
Small capitalization equity securities	**11.6%**	11.4%
International equity securities	**10.6%**	9.8%
Total equity securities	**71.5%**	72.4%
Cash and fixed-income securities	**28.5%**	27.6%
	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 Otter Tail Corporation.
- 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 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 the 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.

On January 31, 2005 the Board of Directors of the Company amended and restated the ESSRP to reduce future benefits effective January 1, 2005, which resulted in reduced expense to the Company. Effective January 1, 2005 new participants in the ESSRP accrue benefits under a new formula. The new formula is the same as the formula used under the Company's qualified defined benefit pension plan but includes bonuses in the computation of covered compensation and is not subject to statutory compensation and benefit limits. Individuals who became participants in the ESSRP before January 1, 2005 will receive the greater of the old formula or the new formula until December 31, 2010. On December 31, 2010, their benefit under the old formula will be frozen. After 2010, they will receive the greater of their frozen December 31, 2010 benefit or their benefit calculated under the new formula. The amendments to the ESSRP also provide for increased service credits for certain participants and eliminate certain distribution features.

On December 19, 2006 the Board of Directors of the Company approved an amendment to the ESSRP effective January 1, 2006. The Amendment amends the ESSRP to provide that for each of the Company's Chief Executive Officer and Corporate Secretary, the "Normal Retirement Benefit" (as defined in the ESSRP) will be determined based on "Final Average Earnings" rather than "Final Annual Salary" (defined as the base Salary (as defined in the ESSRP) and annual bonus paid to the participant during the 12 months prior to termination or death). The ESSRP defines "Final Average Earnings" as the average of the participant's total cash payments (Salary (as defined in the ESSRP) and annual incentive bonus) paid during the highest consecutive 42 months in the 10 years prior to the date as of which the Final Average Earnings are determined.

Components of net periodic pension benefit cost:

(in thousands)	2006	2005	2004
Service cost—benefit earned during the period	$ 426	$ 406	$ 820
Interest cost on projected benefit obligation	1,303	1,267	1,489
Amortization of prior-service cost	71	71	147
Recognized net actuarial loss	473	498	680
Total	$ 2,273	$ 2,242	$ 3,136

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

(in thousands)	2006	2005
Regulatory assets:		
Unrecognized net actuarial loss	$ 5,796	$ —
Unrecognized prior service cost	496	—
Total regulatory asset	6,292	—
Intangible asset		891
Projected benefit obligation liability	(24,783)	
Accumulated benefit obligation liability		(19,631)
Accumulated other comprehensive loss:		
Unrecognized net actuarial loss	3,162	
Unrecognized prior service cost	271	
Total accumulated other comprehensive loss	3,433	4,831
Net amount recognized	$ (15,058)	$ (13,909)

Additional information for the years ended December 31:

(in thousands)	2006	2005
Projected benefit obligation	$ 24,783	$ 23,271
Accumulated benefit obligation	21,317	19,631
Increase in regulatory asset—unrecognized costs	6,292	—
Change in comprehensive loss—unrecognized costs	3,433	—
Change in minimum liability in comprehensive loss	(4,831)	409

Incremental effect of applying SFAS No. 158 to individual balance sheet line items as of December 31, 2006:

(in thousands)	Before SFAS No. 158	Adjustments	After SFAS No. 158
Intangible asset	$ 767	$ (767)	$ —
Regulatory assets	—	6,292	6,292
Liability for pension benefits	21,317	3,466	24,783
Accumulated other comprehensive loss	5,492	(2,059)	3,433

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, 2006 and a statement of the funded status as of December 31 of both years:

(in thousands)	2006	2005
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	$ —	$ —
Actual return on plan assets	—	—
Employer contributions	1,124	1,094
Benefit payments	(1,124)	(1,094)
Fair value of plan assets at December 31	$ —	$ —
Reconciliation of projected benefit obligation:		
Projected benefit obligation at January 1	$ 23,271	$ 23,123
Service cost	426	406
Interest cost	1,303	1,267
Benefit payments	(1,124)	(1,094)
Plan amendments	(53)	(663)
Actuarial loss	960	232
Projected benefit obligation at December 31	$ 24,783	$ 23,271
Reconciliation of funded status:		
Funded status at December 31	$ (24,783)	$ (23,271)
Unrecognized net actuarial loss	8,958	8,471
Unrecognized prior service cost	767	891
Net amount recognized	$ (15,058)	$ (13,909)

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

	2006	2005
Discount rate	6.00%	5.75%
Rate of increase in future compensation level	4.71%	4.69%

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

	2006	2005
Discount rate	5.75%	5.25%
Rate of increase in future compensation level	4.69%	4.69%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2007 are:

(in thousands)	2007
Decrease in regulatory assets:	
Amortization of unrecognized actuarial loss	$ 349
Amortization of unrecognized prior service cost	43
Decrease in accumulated other comprehensive loss:	
Amortization of unrecognized actuarial loss	191
Amortization of unrecognized prior service cost	24
Total estimated amortization	$ 607

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			
2007	2008	2009	2010	2011	2012-2016
$ 1,121	$ 1,105	$ 1,113	$ 1,111	$ 1,202	$ 6,600

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.

During the third quarter of 2004, the Company adopted FASB Staff Position No. FAS 106-2 (FSP 106-2), *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* retroactive to the beginning of 2004. The Company and its actuarial advisors determined that the expected federal subsidy reduced the Company's accumulated postretirement benefit obligation (APBO) at January 1, 2004 by $4,935,000 and reduced its net periodic benefit cost for 2004 by $757,000. The APBO reduction was accounted for as an actuarial experience gain in accordance with the guidance in SFAS No. 106 and was not included as a reduction to the net periodic benefit cost in 2004.

Components of net periodic postretirement benefit cost:

(in thousands)	2006	2005	2004
Service cost—benefit earned during the period	$ 1,319	$ 1,307	$ 1,170
Interest cost on projected benefit obligation	2,556	2,480	2,580
Amortization of transition obligation	748	748	748
Amortization of prior-service cost	(305)	(305)	(305)
Amortization of net actuarial loss	556	742	702
Expense decrease due to Medicare Part D subsidy	(1,543)	(1,251)	(757)
Net periodic postretirement benefit cost	$ 3,331	$ 3,721	$ 4,138

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

(in thousands)	2006	2005
Regulatory asset:		
Unrecognized transition obligation	$ 4,414	$ —
Unrecognized net actuarial gain	(2,077)	—
Unrecognized prior service cost	1,588	—
Net regulatory asset	3,925	—
Projected benefit obligation liability	(32,254)	
Benefit obligation liability		(26,982)
Accumulated other comprehensive loss:		
Unrecognized transition obligation	75	
Unrecognized net actuarial gain	(35)	
Unrecognized prior service cost	27	
Accumulated other comprehensive loss	67	—
Net amount recognized	$ (28,262)	$ (26,982)

Change in regulatory assets and accumulated comprehensive loss due to SFAS No. 158:

(in thousands)	2006
Increase in regulatory asset—net:	
Unrecognized transition obligation	$ 4,414
Unrecognized net actuarial gain	(2,077)
Unrecognized prior service cost	1,588
Net regulatory asset	3,925
Increase in accumulated other comprehensive loss:	
Unrecognized transition obligation	75
Unrecognized net actuarial gain	(35)
Unrecognized prior service cost	27
Accumulated other comprehensive loss	67
Total change	$ 3,992

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, 2006:

(in thousands)	2006	2005
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	$ —	$ —
Actual return on plan assets	—	—
Company contributions	2,051	1,792
Benefit payments (net of Medicare Part D subsidy)	(3,625)	(3,112)
Participant premium payments	1,574	1,320
Fair value of plan assets at December 31	$ —	$ —
Reconciliation of projected benefit obligation:		
Projected benefit obligation at January 1	$ 36,757	$ 39,639
Service cost (net of Medicare Part D subsidy)	1,110	1,172
Interest cost (net of Medicare Part D subsidy)	1,779	1,998
Benefit payments (net of Medicare Part D subsidy)	(3,625)	(3,112)
Participant premium payments	1,574	1,320
Actuarial gain	(5,341)	(4,260)
Projected benefit obligation at December 31	$ 32,254	$ 36,757
Reconciliation of accrued postretirement cost:		
Accrued postretirement cost at January 1	$ (26,982)	$ (25,053)
Expense	(3,331)	(3,721)
Net company contribution	2,051	1,792
Accrued postretirement cost at December 31	$ (28,262)	$ (26,982)

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

	2006	2005
Discount rate	6.00%	5.75%

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

	2006	2005
Discount rate (2005 is remeasurement composite rate)	5.75%	5.625%

Assumed healthcare cost-trend rates as of December 31:

	2006	2005
Healthcare cost-trend rate assumed for next year pre-65	9.00%	9.00%
Healthcare cost-trend rate assumed for next year post-65	10.00%	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	2012	2010

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 2006 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on total of service and interest cost	$ 433	$ (350)
Effect on the postretirement benefit obligation	$ 2,926	$ (2,691)

Measurement dates:	2006	2005
Net periodic postretirement benefit cost	January 1, 2006	January 1, 2005 & July 1, 2005
End of year benefit obligations	January 1, 2006 projected to December 31, 2006	January 1, 2005 projected to December 31, 2005

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 2007 are:

(in thousands)	2007
Decrease in regulatory assets:	
Amortization of transition obligation	$ 735
Accumulation of unrecognized prior service cost	(203)
Decrease in accumulated other comprehensive loss:	
Amortization of transition obligation	13
Accumulation of unrecognized prior service cost	(3)
Total estimated amortization	$ 542

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 2007. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands) Years					
2007	2008	2009	2010	2011	2012–2016
$ 2,391	$ 2,357	$ 2,431	$ 2,433	$ 2,564	$ 13,895

The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $439,000 in 2007.

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 2006, $830,000 for 2005 and $930,000 for 2004.

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.

OTHER INVESTMENTS

The carrying amount approximates fair value. A portion of other investments is in financial instruments that have variable interest rates that reflect fair value. The remainder of other investments is accounted for by the equity method which, in the case of operating losses, results in a reduction of the carrying amount.

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, 2006		December 31, 2005	
(in thousands)	Carrying Amount	Fair value	Carrying amount	Fair value
Cash and short-term investments	$ 6,791	$ 6,791	$ 5,430	$ 5,430
Other investments	8,955	8,955	8,702	8,702
Long-term debt	(255,436)	(265,547)	(258,260)	(273,456)

14. PROPERTY, PLANT AND EQUIPMENT

(in thousands)	**December 31, 2006**	December 31, 2005
Electric plant		
Production	**$ 360,304**	$ 357,285
Transmission	**189,683**	182,502
Distribution	**307,825**	296,301
General	**72,877**	74,678
Electric plant	**930,689**	910,766
Less accumulated depreciation and amortization	**388,254**	374,786
Electric plant net of accumulated depreciation	**542,435**	535,980
Construction work in progress	**18,503**	12,449
Net electric plant	**$ 560,938**	$ 548,429
Nonelectric operations plant	**$ 239,269**	$ 228,548
Less accumulated depreciation and amortization	**91,303**	84,652
Nonelectric plant net of accumulated depreciation	**147,966**	143,896
Construction work in progress	**9,705**	4,766
Net nonelectric operations plant	**$ 157,671**	$ 148,662
Net plant	**$ 718,609**	$ 697,091

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	3	40

15. INCOME TAXES

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2006, 2005 and 2004) to net income before total income tax expense for the following reasons:

(in thousands)	**2006**	2005	2004
Tax computed at federal statutory rate	**$ 27,232**	$ 28,325	$ 20,253
Increases (decreases) in tax from:			
State income taxes net of federal income tax benefit	**2,261**	1,906	1,808
Investment tax credit amortization	**(1,146)**	(1,151)	(1,152)
Differences reversing in excess of federal rates	**1,271**	(15)	(136)
Dividend received/paid deduction	**(718)**	(703)	(703)
Affordable housing tax credits	**(839)**	(1,324)	(1,418)
Permanent and other differences	**(955)**	969	(1,286)
Total income tax expense	**$ 27,106**	$ 28,007	$ 17,366
Income tax expense— discontinued operations	**$ 252**	$ 5,570	$ 1,121
Overall effective federal and state income tax rate	**34.9%**	34.9%	30.5%
Income tax expense includes the following:			
Current federal income taxes	**$ 26,276**	$ 32,795	$ 15,228
Current state income taxes	**4,232**	5,265	2,913
Deferred federal income taxes	**(937)**	(7,112)	1,776
Deferred state income taxes	**(189)**	(899)	194
Affordable housing tax credits	**(839)**	(1,324)	(1,418)
Investment tax credit amortization	**(1,146)**	(1,151)	(1,152)
Foreign income taxes	**(291)**	433	(175)
Total	**$ 27,106**	$ 28,007	$ 17,366

The Company's deferred tax assets and liabilities were composed of the following on December 31, 2006 and 2005:

(in thousands)	**2006**	2005
Deferred tax assets		
Amortization of tax credits	**$ 5,231**	$ 5,964
Vacation accrual	**2,751**	2,432
Unearned revenue	**2,013**	2,803
Benefit liabilities	**29,418**	29,657
SFAS 158 liabilities	**14,694**	—
Cost of removal	**22,813**	20,507
Differences related to property	**7,923**	7,400
Other	**3,382**	3,689
Total deferred tax assets	**$ 88,225**	$ 72,452
Deferred tax liabilities		
Differences related to property	**$ (160,635)**	$(154,833)
Excess tax over book pension	**(3,153)**	(3,861)
Transfer to regulatory asset	**(11,712)**	(16,724)
SFAS 158 regulatory asset	**(14,694)**	—
Other	**(2,702)**	(3,900)
Total deferred tax liabilities	**$ (192,896)**	$(179,318)
Deferred income taxes	**$ (104,671)**	$(106,866)

16. DISCONTINUED OPERATIONS

In 2006, the Company sold the natural gas marketing operations of OTESCO, the Company's energy services subsidiary. Discontinued operations includes the operating results of OTESCO's natural gas marketing operations for 2006, 2005 and 2004. Discontinued operations also includes an after-tax gain on the sale of OTESCO's natural gas marketing operations of $0.3 million in 2006.

In 2005, the Company sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Discontinued operations includes the operating results of MIS, SGS and CLC for 2005 and 2004. Discontinued operations also includes an after-tax gain on the sale of MIS of $11.9 million, an after-tax loss on the sale of SGS of $1.7 million and an after-tax loss on the sale of CLC of $0.2 million in 2005. OTESCO's natural gas marketing operations, *MIS, SGS and CLC meet requirements* to be reported as discontinued operations in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

The results of discontinued operations for the years ended December 31, 2006, 2005 and 2004 are summarized as follows:

2006 *(in thousands)*	OTESCO Gas
Operating revenues	**$ 28,234**
Income before income taxes	**54**
Gain on disposition —pretax	**560**
Income tax expense	**252**

2005 *(in thousands)*	OTESCO Gas	MIS	SGS	CLC	Total
Operating revenues	$ 64,539	$ 3,773	$ 6,564	$ 6,112	$ 80,988
Income (loss) before income taxes	(84)	2,167	(1,740)	(956)	(613)
Goodwill impairment loss	(1,003)	—	—	—	(1,003)
Gain (loss) on disposition —pretax	—	19,025	(2,919)	(271)	15,835
Income tax (benefit) expense	(40)	7,975	(1,863)	(502)	5,570

2004 *(in thousands)*	OTESCO Gas	MIS	SGS	CLC	Total
Operating revenues	$ 44,326	$ 8,739	$ 17,209	$ 7,753	$ 78,027
Income (loss) before income taxes	211	3,698	(932)	(163)	2,814
Income tax expense (benefit)	81	1,483	(371)	(72)	1,121

At December 31, 2006 and 2005 the major components of assets and liabilities of the discontinued operations were as follows:

	December 31, 2006	December 31, 2005			
(in thousands)	SGS	OTESCO Gas	SGS	CLC	Total
Current assets	$ 289	$ 11,384	$ 857	$ 1,455	$ 13,696
Investments and other assets	–	–	–	5	5
Assets of discontinued operations	$ 289	$ 11,384	$ 857	$ 1,460	$ 13,701
Current liabilities	$ 197	$ 10,611	$ 328	$ 44	$ 10,983
Liabilities of discontinued operations	$ 197	$ 10,611	$ 328	$ 44	$ 10,983

The remaining assets and liabilities of SGS consist of deferred taxes and warranty reserves at estimated fair market values that were not settled or disposed of as of December 31, 2006.

17. ASSET RETIREMENT OBLIGATIONS *(AROs)*

The Company's AROs are related to coal-fired generation plants and include site restoration, closure of ash pits, and removal of storage tanks 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 2006, the Company did not record any new obligation or make any revisions to previously recorded obligations. The Company settled a legal obligation for removal of asbestos at unit one of its Hoot Lake generating plant. The Company did not settle any asset retirement obligations in 2005 or 2004.

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, 2006 and 2005 are presented in the following table:

(in thousands)	2006	2005
Asset retirement obligations		
Beginning balance	$ 1,524	$ 1,437
New obligations recognized	–	–
Adjustments due to revisions in cash flow estimates	–	–
Accrued accretion	85	87
Settlements	(274)	–
Ending balance	$ 1,335	$ 1,524
Asset retirement costs capitalized		
Beginning balance	$ 349	$ 349
New obligations recognized	–	–
Adjustments due to revisions in cash flow estimates	–	–
Settlements	(64)	–
Ending balance	$ 285	$ 349
Accumulated depreciation—asset retirement costs capitalized		
Beginning balance	$ 234	$ 225
New obligations recognized	–	–
Adjustments due to revisions in cash flow estimates	–	–
Accrued depreciation	8	9
Settlements	(64)	–
Ending balance	$ 178	$ 234
Settlements		
Original capitalized asset retirement cost—retired	$ 64	$ –
Accumulated depreciation	(64)	–
Asset retirement obligation	$ 274	$ –
Settlement cost	(222)	–
Gain on settlement—deferred under regulatory accounting	$ 52	$ –

18. 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)	2006	2005	2006	2005	2006	2005	2006	2005
Operating revenues (a)	$ 257,807	$ 216,084	$ 279,904	$ 245,799	$ 280,542	$ 261,187	$ 286,701	$ 258,799
Operating income (a)	27,374	21,107	22,136	20,821	24,170	33,479	24,117	23,188
Net income:								
Continuing operations	14,855	11,076	11,137	10,952	13,476	19,168	11,282	12,706
Discontinued operations	105	(1,105)	257	11,352	–	(1,565)	–	(33)
	14,960	9,971	11,394	22,304	13,476	17,603	11,282	12,673
Earnings available for common shares:								
Continuing operations	14,671	10,892	10,953	10,769	13,293	18,983	11,097	12,523
Discontinued operations	105	(1,105)	257	11,352	–	(1,565)	–	(33)
	14,776	9,787	11,210	22,121	13,293	17,418	11,097	12,490
Basic earnings per share:								
Continuing operations	$ .50	$ .37	$ .37	$ .37	$ .45	$ .65	$ .38	$ .43
Discontinued operations	–	(.03)	.01	.39	–	(.05)	–	–
	.50	.34	.38	.76	.45	.60	.38	.43
Diluted earnings per share:								
Continuing operations	.50	$ .37	.37	$ .37	.45	$ .64	37	$ .42
Discontinued operations	–	(.04)	.01	.39	–	(.05)	–	–
	.50	.33	.38	.76	.45	.59	.37	.42
Dividends paid per common share	.2875	.28	.2875	.28	.2875	.28	.2875	.28
Price range:								
High	$ 31.34	$ 25.87	$ 30.09	$ 27.77	$ 30.80	$ 31.95	$ 31.92	$ 31.95
Low	27.32	24.17	25.78	24.02	26.50	27.20	28.60	26.76
Average number of common shares outstanding—basic	29,326	29,126	29,393	29,158	29,413	29,246	29,445	29,361
Average number of common shares outstanding—diluted	29,676	29,230	29,766	29,264	29,806	29,441	29,731	29,555

(a) From continuing operations.

CONSOLIDATED STATISTICAL SUPPLEMENT

OPERATING RATIOS

(in thousands)	**2006**	2005	2004	2003	2002	2001	1996
Operating revenues (a)	**$ 1,104,954**	$ 981,869	$ 813,036	$ 688,989	$ 595,425	$ 526,570	$ 351,128
Operating expenses (a) (b)	**$ 1,007,157**	$ 883,274	$ 737,826	$ 620,026	$ 516,495	$ 456,600	$ 294,612
Operating ratio (a)	**91.1**	90.0	90.7	90.0	86.7	86.7	83.9

SELECTED COMMON SHARE DATA

(in thousands)	**2006**	2005	2004	2003	2002	2001	1996
Earnings available for common shares	**$ 50,376**	$ 61,816	$ 41,459	$ 38,921	$ 45,392	$ 41,610	$ 28,266
Average number of shares—diluted	**29,664**	29,348	26,207	25,826	25,397	24,832	23,007
Diluted earnings per share	**$ 1.70**	$ 2.11	$ 1.58	$ 1.51	$ 1.79	$ 1.68	$ 1.23
Common dividends	**$ 33,886**	$ 32,728	$ 28,528	$ 27,730	$ 26,729	$ 25,256	$ 20,124
Dividends paid per share	**$ 1.15**	$ 1.12	$ 1.10	$ 1.08	$ 1.06	$ 1.04	$ 0.90
Payout ratio	**68%**	53%	70%	72%	59%	62%	73%
Market price:							
High	**$ 31.92**	$ 31.95	$ 27.50	$ 28.90	$ 34.90	$ 31.00	$ 19.31
Low	**$ 25.78**	$ 24.02	$ 23.77	$ 23.76	$ 22.82	$ 23.00	$ 15.88
Common price/earnings ratio:							
High	**18.8**	15.1	17.4	19.1	19.5	18.5	15.7
Low	**15.2**	11.4	15.0	15.7	12.7	13.7	12.9
Book value per common share	**$ 16.62**	$ 15.80	$ 14.81	$ 12.98	$ 12.25	$ 11.33	$ 8.50

SELECTED DATA AND RATIOS

	2006	2005	2004	2003	2002	2001	1996
Net income (in thousands)	**$ 51,112**	$ 62,551	$ 42,195	$ 39,656	$ 46,128	$ 43,603	$ 30,624
Interest coverage before taxes (a)	**5.2x**	5.7x	4.4x	4.1x	4.7x	4.8x	3.7x
Effective income tax rate (percent) (a)	**35**	34	30	27	30	30	32
Capital ratios:							
Long-term debt and current maturities (percent)	**33.7**	35.2	37.5	43.6	44.2	45.8	45.3
Preferred stock and other equity (percent)	**2.2**	2.3	2.4	2.5	2.6	2.9	9.0
Common equity (percent)	**64.1**	62.5	60.1	53.9	53.2	51.3	45.7
	100.0	100.0	100.0	100.0	100.0	100.0	100.0

CAPITALIZATION

(in thousands)	**2006**	2005	2004	2003	2002	2001	1996
Long-term debt and current maturities	**$ 258,561**	$ 261,600	$ 267,821	$ 270,597	$ 260,302	$ 249,188	$ 194,602
Preferred stock and other equity	**16,755**	16,758	17,332	15,500	15,500	15,500	38,831
Common stock equity:							
Par	**147,609**	147,006	144,885	128,619	127,961	123,267	57,680
Premium	**99,223**	96,768	87,865	26,515	24,135	1,526	29,885
Unearned compensation	**—**	(1,720)	(2,577)	(3,313)	(1,946)	(151)	—
Retained earnings and other comprehensive loss	**243,938**	222,376	199,037	182,066	163,315	154,666	108,483
Total common equity	**$ 490,770**	$ 464,430	$ 429,210	$ 333,887	$ 313,465	$ 279,308	$ 196,048
Total capitalization including current maturities	**$ 766,086**	$ 742,788	$ 714,363	$ 619,984	$ 589,267	$ 543,996	$ 429,481
Income before interest charges (includes AFC borrowed) (a)	**$ 70,484**	$ 72,551	$ 58,863	$ 56,535	$ 62,575	$ 55,485	$ 45,341
Percent return on capitalization (a)	**9.2**	9.8	8.2	9.1	10.6	10.2	10.6
Percent return on average common equity	**10.6**	13.9	12.0	12.2	15.3	15.5	14.9

TIMES INTEREST EARNED AND PREFERRED DIVIDEND COVERAGE (a)

	2006	2005	2004	2003	2002	2001	1996
Before income taxes:							
Long-term debt interest (c)	**6.2**	6.4	4.9	4.3	5.0	4.9	3.9
After income taxes:							
Long-term debt interest (d)	**4.5**	4.6	3.8	3.4	3.8	3.8	3.0
Long-term debt interest and preferred dividends (e)	**4.3**	4.4	3.6	3.3	3.7	3.3	2.6
Preferred dividends (f)	**69.0**	73.3	55.0	52.1	60.2	19.9	12.3

(a) *2005 and prior years restated to exclude discontinued operations.*
(b) Excludes income taxes
(c) Income before interest charges + income taxes ÷ long-term debt interest
(d) Income before interest charges ÷ long-term debt interest
(e) Income before interest charges ÷ long-term debt interest and preferred dividends
(f) Net income ÷ preferred dividends

ELECTRIC UTILITY STATISTICAL SUPPLEMENT

DEPRECIATION RESERVE

(in thousands)	**2006**	2005	2004	2003	2002	2001	1996
Electric plant in service	**$ 930,689**	$ 910,766	$ 890,200	$ 875,364	$ 835,382	$ 810,470	$ 742,065
Depreciation reserve	**$ 388,254**	$ 374,786	$ 363,696	$ 368,899	$ 357,555	$ 341,004	$ 267,203
Reserve to electric plant (percent)	**41.7**	41.2	40.9	42.1	42.8	42.1	36.0
Composite depreciation rate (percent)	**2.82**	2.74	2.77	3.07	3.08	3.06	3.00

RATIO OF DEBT TO ELECTRIC PLANT

(in thousands)	**2006**	2005	2004	2003	2002	2001	1996
Electric plant:							
Gross (a)	**$ 949,191**	$ 923,215	$ 902,412	$ 889,302	$ 874,505	$ 835,564	$ 753,536
Net	**$ 560,937**	$ 548,429	$ 538,716	$ 520,403	$ 516,950	$ 494,560	$ 486,332
Debt (b)	**$ 166,975**	$ 166,975	$ 166,975	$ 166,975	$ 166,975	$ 155,485	$ 137,995
Ratio to electric plant—net (a) (percent)	**30**	30	31	32	32	31	28

PEAK DEMAND AND NET GENERATING CAPABILITY

	2006	2005	2004	2003	2002	2001	1996
Peak demand (kw)	**680,331**	665,064	686,044	668,703	640,220	630,262	635,320
Net generating capability (kw):							
Steam	**549,350**	559,175	554,330	555,085	557,308	557,400	546,909
Combustion turbines	**137,595**	135,701	136,506	136,915	87,358	89,085	91,123
Hydro	**4,294**	4,244	4,327	4,380	4,336	4,365	4,353
Total owned generating capability	**691,239**	699,120	695,163	696,380	649,002	650,850	642,385

ELECTRIC INVESTMENT

	2006	2005	2004	2003	2002	2001	1996
Electric utility plant—net (c) (in thousands)	**$ 560,937**	$ 548,429	$ 538,716	$ 520,403	$ 516,950	$ 494,560	$ 486,332
Total retail electric revenue (in thousands)	**$ 260,926**	$ 248,939	$ 224,326	$ 217,439	$ 206,870	$ 199,101	$ 183,737
Total retail electric customers	**129,070**	128,406	128,157	127,474	127,093	126,548	124,730
Investment per dollar revenue	**$ 2.15**	$ 2.20	$ 2.40	$ 2.39	$ 2.50	$ 2.48	$ 2.65
Investment per customer	**$ 4,346**	$ 4,271	$ 4,204	$ 4,082	$ 4,067	$ 3,908	$ 3,899

OUTPUT KILOWATT-HOURS

(in thousands)	**2006**	2005	2004	2003	2002	2001	1996
Net generated	**3,571,410**	3,513,705	3,774,115	3,672,616	3,548,413	3,765,265	2,635,405
Purchased, net interchange and financial settlements	**3,218,537**	3,495,176	4,910,428	5,898,456	4,135,932	3,224,662	2,523,676
Total	**6,789,947**	7,008,881	8,684,543	9,571,072	7,684,345	6,989,927	5,159,081

(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, Fargo Forum* 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 and has increased them annually since 1975. 2006 dividends were $1.15 per share. The indicated annual rate for 2007 is $1.17. The 2006 yield was 4.0% and the 2006 payout ratio was 68%. Total shareholder return grew at a compounded average annual rate of 11.6% 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 76% of eligible shareowners holding about 15% 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, including institutional holders, 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
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: 800-664-1259 or 218-739-8479

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

2007 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 9, 2007 10 A.M., Central Time
Bigwood Event Center
921 Western Avenue
Fergus Falls, Minnesota

EX-DIVIDEND	RECORD	PAYMENT	
Feb. 13	Feb. 15	P	Mar. 1
		C	Mar. 10
May 11	May 15	P	June 1
		C	June 9
Aug. 13	Aug. 15	P	Sept. 1
		C	Sept. 10
Nov. 13	Nov. 15	P	Dec. 1
		C	Dec. 10

KEY STATISTICS

NASDAQ	OTTR
Senior unsecured debt ratings	
Moody's Investor Service	A3/stable
Standard & Poor's	BBB+/stable
Year-end stock price	$31.16
Year-end price/earnings ratio	18.3
Year-end market-to-book ratio	1.9
Annual dividend yield	4.0%
Shares outstanding	29.5 million
Market capitalization *(as of December 31, 2006)*	$920 million
2006 average daily trading volume	82,248
Institutional holdings *(shares as of December 31, 2006)*	11.2 million

2007 CASH INVESTMENT AND SELL DATES FOR DIVIDEND REINVESTMENT

JAN. 2	FEB. 1	MAR. 1	APRIL 2	MAY 1	JUNE 1	JULY 2	AUG. 1	SEPT. 4	OCT. 1	NOV. 1	DEC. 3

DIRECTORS

A *Audit Committee*
C *Compensation Committee*
CG *Corporate Governance Committee*
E *Executive Committee*

JOHN C. MACFARLANE › (67-24)* E
Chairman of the Board of Directors
Fergus Falls, Minnesota
Retired President and Chief Executive Officer, Otter Tail Corporation

KAREN M. BOHN › (53-3) A/CG/E
Edina, Minnesota
President, Galeo Group, LLC
(management consulting firm)

DENNIS R. EMMEN › (73-23) A/C
Fergus Falls, Minnesota
Retired Senior Vice President, Finance, Treasurer and Chief Financial Officer, Otter Tail Power Company

ARVID R. LIEBE › (65-12) C/CG/E
Milbank, South Dakota
President, Liebe Drug, Inc. (retail business)
Owner, Liebe Farms, Inc.

EDWARD J. MCINTYRE › (56-1) A/C
Incline Village, Nevada
Retired Vice President and Chief Financial Officer, Xcel Energy
(electricity and natural gas energy company)

JOYCE NELSON SCHUETTE › (56-1) C/CG
Minneapolis, Minnesota
Retired Managing Director and Investment Banker, Piper Jaffray & Co.
(financial services)

KENNETH L. NELSON › (65-17) A
Perham, Minnesota
President and Chief Executive Officer, Barrel O' Fun, Inc.; Kenny's Candy, Inc.; Tuffy's Pet Foods, Inc.
(snack and pet foods manufacturers)

NATHAN I. PARTAIN › (50-14) 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 › (65-6) A/CG
Fergus Falls, Minnesota
Chairman, Service Food, Inc., (retail business)
Partner, Fergus Falls Development Company and Midwest Regional Development Company, LLC
(land and housing development)

OFFICERS

JOHN D. ERICKSON
(48-26)*
President and Chief Executive Officer

LAURIS N. MOLBERT
(49-12)
Executive Vice President and Chief Operating Officer

KEVIN G. MOUG
(47-10)
Chief Financial Officer and Treasurer

GEORGE A. KOECK
(54-7)
General Counsel and Corporate Secretary

VICE PRESIDENTS

CHARLES S. MACFARLANE
(42-5)*
Electric Platform

CHARLES R. HOGE
(50-4)
Manufacturing Platform

PAUL J. WILSON
(48-1)
Health Services Platform

W. RICHARD NICKEL
(64-2)
Food Ingredient Processing Platform

SHANE N. WASLASKI
(31-4 months)
Infrastructure Products and Services Platform

LORI A. TALAFOUS
(49-1)
Vice President of Human Resources and Strategy

*(Age-years of service) are as of the 2007 Annual Meeting of Shareholders.

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END