OTTR 10-K 12/31/2003

Section 1: 10-K (FORM 10-K)

Table of Contents

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One) (X) Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended **December 31, 2003**

OR

( ) Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from________to__________

Commission File Number **0-368**

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

MINNESOTA (State or other jurisdiction of incorporation or organization)	**41-0462685** (I.R.S. Employer Identification No.)
215 SOUTH CASCADE STREET BOX 496, FERGUS FALLS, MINNESOTA (Address of principal executive offices)	**56538-0496** (Zip Code)

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

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

Title of each class	Name of each exchange on which registered
NONE	**NONE**

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

COMMON SHARES, par value $5.00 per share
PREFERRED SHARE PURCHASE RIGHTS
CUMULATIVE PREFERRED SHARES, without par value
(Title of class)

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). (Yes **X** No)

The aggregate market value of the voting stock held by nonaffiliates on June 30, 2003 was
$675,261,753.

Indicate the number of shares outstanding of each of the registrant's classes of Common Stock, as of the latest practicable date:
25,785,928 Common Shares ($5 par value) as of February 27, 2004.

Documents Incorporated by Reference:

2003 Annual Report to Shareholders-Portions incorporated by reference into Parts I and II
Proxy Statement dated March 17, 2004-Portions incorporated by reference into Part III

TABLE OF CONTENTS

PART I

Item 1. BUSINESS

(a) General Development of Business

Otter Tail Corporation (the Company) was incorporated in 1907 under the laws of the State of Minnesota. The Company's executive offices are located at 215 South Cascade Street, Box 496, Fergus Falls, Minnesota 56538-0496 and 4334 18th Avenue SW, Suite 200, P.O. Box 9156, Fargo, North Dakota 58106-9156. Its telephone number is (866) 410-8780.

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

In the late 1980s, the Company determined that its core electric business was located in a region of the country where there was little growth in the demand for electricity. In order to maintain growth for shareholders, Otter Tail Power Company (as the Company was known) began to explore opportunities for the acquisition and long-term ownership of nonelectric businesses. This strategy has resulted in steady growth over the years. In 2001, the name of the Company was changed to "Otter Tail Corporation" to more accurately represent the broader scope of electric and nonelectric operations and the name "Otter Tail Power Company" was retained for use by the electric utility. In 2003, approximately 64% of the Company's consolidated revenues and approximately 14% of the Company's consolidated net income came from nonelectric operations.

The Company's strategy is focused on the growth of its operating companies. The Company's goal is to create value and growth through the acquisition, long-term ownership and decentralized operation of diverse businesses. The Company's electric utility provides a strong base of revenues, cash flows and earnings as part of this strategy. The following guidelines are considered when reviewing potential acquisition candidates:

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

The Company assesses the performance of its operating companies as follows:

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

The Company will consider divesting operating companies if they do not meet these criteria over the long term.

Otter Tail Corporation and its subsidiaries conducted business in 48 states and 6 Canadian provinces and had approximately 2,730 full-time employees at December 31, 2003. The businesses of the Company have been classified into five segments: Electric, Plastics, Manufacturing, Health Services and Other Business Operations.

- Electric (the Utility) includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company. Electric utility operations have been the Company’s primary business since incorporation.

- 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, frame-straightening equipment and accessories for the auto body shop industry, custom plastic pallets, material and handling trays and horticultural containers; fabrication of steel products; contract machining; and metal parts stamping and fabrication. These businesses are located primarily in the Upper Midwest, Missouri and Utah.

- 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 service maintenance, mobile diagnostic imaging, mobile positron emission tomography and nuclear medicine imaging, portable X-ray imaging and rental of diagnostic medical imaging equipment to various medical institutions located in 42 states.

- Other Business Operations consists of businesses in electrical and telephone construction contracting, specialty contracting including design-and-build services for new construction, transportation, telecommunications, energy services and natural gas marketing 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.

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

The Company continues to look for acquisitions of additional businesses and expects continued growth in this area. The following acquisitions were completed during 2003:

- On November 1, 2003 the Company acquired the assets and operations of Foley Company (Foley) for $12.3 million in cash. Foley is a mechanical and prime contracting firm based in Kansas City, Missouri, that provides a range of specialty contracting including design-and-build services for new construction, retrofitting, process piping, equipment settings, and instrumentation and control systems. Major clients include water and wastewater treatment plants, hospital and pharmaceutical facilities, power generation plants, and other industrial and manufacturing projects across a multi-state service area in the Central United States. Foley had gross revenues of $44.8 million in 2002. This acquisition expands the Company’s construction services to a broader geographic region. Foley is included in the Other Business Operations segment.

- During 2003, the Company also acquired Topline Medical, Inc. and North Star Medical Systems, Inc. The aggregate price paid for the companies was $1.9 million in cash. These acquisitions will allow the Health Services segment to increase sales opportunities with an expanded line of products.

The Utility has indicated interest in the South Dakota-based electric and gas operations of NorthWestern Corporation, which filed for bankruptcy in the fall of 2003 and is currently restructuring. The Utility's interest does not include NorthWestern's Montana property or operations. Because the process has just begun, it is not possible to determine the likelihood of the acquisition being completed.

For a discussion of the Company's results of operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations," which is incorporated by reference to pages 18 through 30 of the Company's 2003 Annual Report to Shareholders, filed as an Exhibit hereto.

(b) Financial Information About Industry Segments

The Company is engaged in businesses that have been classified into five segments: Electric, Plastics, Manufacturing, Health Services and Other Business Operations. Financial information about the Company's segments is incorporated by reference to note 2 of "Notes to Consolidated Financial Statements" on pages 41 and 42 of the Company's 2003 Annual Report to Shareholders, filed as an Exhibit hereto.

(c) Narrative Description of Business

ELECTRIC

General

The Utility, which conducts business under the name of Otter Tail Power Company, provides electricity to more than 127,000 customers in a 50,000 square mile area of Minnesota, North Dakota and South Dakota. The Company derived 36% of its consolidated operating revenues from the Electric segment in 2003, 38% in 2002, and 40% in 2001. The breakdown of retail revenues by state is as follows:

State	2003	2002
Minnesota	50.2%	50.5%
North Dakota	41.4	41.2
South Dakota	8.4	8.3
Total	100.0%	100.0%

The territory served by the Utility is predominantly agricultural, including a part of the Red River Valley. Although there are relatively few large customers, sales to commercial and industrial customers are significant. The following table provides a breakdown of electric revenues by customer category. All other sources include gross wholesale sales and sales to municipalities and farms.

Customer category	2003	2002
Commercial	24.6%	29.1%
Residential	21.2	25.0
Industrial	13.8	15.8
All other sources	40.4	30.1
Total	100.0%	100.0%

Wholesale electric energy sales increased from 45.2% of total kwh sales in 2002 to 50.5% of total kwh sales in 2003. Wholesale electric energy kwh sales grew 24.2% between the years and revenue per kwh increased by 36.1%. Activity in the short-term energy market is subject to change based on a number of factors and it is difficult to predict the quantity of wholesale power sales or prices for wholesale power in the future. However, the Company expects that market conditions for wholesale power transactions in 2004 will not be as robust as in 2003.

The aggregate population of the Utility's retail electric service area is approximately 230,000. In this service area of 423 communities and adjacent rural areas and farms, approximately 130,900 people live in communities having a population of more than 1,000, according to the 2000 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,527); Fergus Falls, Minnesota (13,471); and Bemidji, Minnesota (11,917). As of December 31, 2003 the Utility served 127,534 customers. This is an increase of 377 customers from December 31, 2002.

Capability and Demand

At December 31, 2003 and 2002 the Utility had base load net plant capability as follows:

Base load net plant capability	2003	2002
Big Stone Plant	252,360 kw	253,508 kw
Hoot Lake Plant	153,275	154,350
Coyote Station	149,450	149,450
Co-generation plant - Bemidji, MN (contract)	5,875	5,950
Co-generation plant - Perham, MN (contract)	2,378	—
Total	563,338 kw	563,258 kw

The base load net plant capability for Big Stone Plant and Coyote Station constitutes the Utility's ownership percentages of 53.9% and 35% respectively.

In addition to its base load capability, the Utility has combustion turbine and small diesel units owned or under contract, used chiefly for peaking and standby purposes, with a total capability of 142,026 kw, and hydroelectric capability of 4,380 kw. The Utility completed the installation of a peaking combustion turbine in May 2003 with a generation capability of 44,700 kw in summer and 49,500 kw in winter. During 2003, the Utility generated about 79% of its retail kwh sales and purchased the balance.

The Utility has arrangements to help meet its future base load requirements and continues to investigate other means for meeting such requirements. The Utility has an agreement with another utility for the annual exchange of 75,000 kw of seasonal capacity which runs through October 2004. The Utility has an agreement to purchase 50,000 kw of year-round capacity which extends through April 30, 2005 and another agreement to purchase 50,000 kw of year-round capacity through April 30, 2010 from another utility. In 2003 the Utility also had a seasonal capacity agreement to purchase 10,000 kw for the months of June and September. The Utility has agreements to purchase the output from approximately 23,000 kw (nameplate rating) of wind generating facilities. The Utility has a direct control load management system which provides some flexibility to the Utility to effect reductions of peak load. The Utility, in addition, offers rates to customers which encourage off-peak usage.

The Utility traditionally experiences its peak system demand during the winter season. For the year ended December 31, 2003 the Utility experienced an all-time system peak demand of 668,703 kw on February 10, 2003. The highest sixty-minute peak demand prior to 2003 was 642,826 kw on December 14, 2000. Taking into account additional capacity available to it in February 2003 under purchase power contracts (including short-term arrangements), as well as its own generating capacity, the Utility's capability of then meeting system demand, including reserve requirements computed in accordance with accepted industry practice, amounted to 837,590 kw. The Utility's additional capacity available under power purchase contracts (as described above), combined with generating capability and load management control capabilities, is expected to meet 2004 system demand, including industry reserve requirements.

The Utility and a coalition of other electric providers are funding a study to explore the feasibility of a second electric generating unit, tentatively named Big Stone II, next to the site of the existing Big Stone Plant near Milbank, South Dakota. The project would serve the investing providers' native customer loads and would be nominally rated between 400 and 600 megawatts, rate-based and coal fired or coal-and-biomass fired. If the investing providers decide to proceed, they are expected to sign ownership and operating agreements in 2004. Permitting, which would require two years, and construction, which would require three years, could lead to the plant being operational in 2010. The Utility's ownership investment is expected to be less than 25% in the project.

Fuel Supply

Coal is the principal fuel burned at the Big Stone, Coyote and Hoot Lake generating plants. Coyote, a mine-mouth facility, burns North Dakota lignite coal. Hoot Lake and Big Stone plants burn western subbituminous coal.

The following table shows the sources of energy used to generate the Utility's net output of electricity for 2003 and 2002:

	2003		2002	
Sources	**Net Kilowatt Hours Generated (Thousands)**	**% of Total Kilowatt Hours Generated**	**Net Kilowatt Hours Generated (Thousands)**	**% of Total Kilowatt Hours Generated**
Subbituminous Coal	2,668,421	72.7%	2,459,046	69.3%
Lignite Coal	955,304	26.0	1,063,942	30.0
Hydro	14,778	.4	24,220	.7
Natural Gas and Oil	34,114	.9	1,205	.0
Total	3,672,617	100.0%	3,548,413	100.0%

The Utility has a primary coal supply agreement with RAG Coal West, Inc. for the supply of Wyoming subbituminous coal to Big Stone Plant for 2004. The Company is in negotiations with a new coal supplier for a long-term contract beginning in 2005. Purchases are made for the supply of subbituminous coal for the Hoot Lake Plant under a contract with Kennecott Coal Sales Company expiring June 30, 2004. The Company is in negotiations with the Kennecott Coal Sales Company for a new coal contract for the Hoot Lake Plant that is expected to be in place before June 30, 2004. Costs are expected to remain stable. A lignite coal contract with Dakota Westmoreland Corporation for the Coyote Station expires in 2016, with a 15-year renewal option subject to certain contingencies.

It is the Utility's practice to maintain minimum 30-day inventory (at full output) of coal at the Big Stone Plant, a 20-day inventory at the Coyote Station and a 10-day inventory at the Hoot Lake Plant.

Railroad transportation services to the Big Stone Plant are being provided under a common carrier rate by the Burlington Northern and Santa Fe Railroad Co. The Company has filed a complaint in regard to this rate with the Surface Transportation Board requesting the Board set a competitive rate. The Surface Transportation Board is not likely to act on this complaint until early in 2005. The Company would expect the outcome of the proceeding to have a favorable impact on its fuel costs for Big Stone Plant. An agreement is in place with the Burlington Northern and Santa Fe Railroad for Hoot Lake Plant which expires on July 31, 2004. The Company is working on a new coal transportation agreement with the Burlington Northern and Santa Fe Railroad for Hoot Lake Plant. The Company is not expecting significant changes to this agreement. No coal transportation agreement is needed for the Coyote Station due to its location next to a coal mine.

The average cost of coal consumed (including handling charges to the plant sites) per million BTU for each of the three years 2003, 2002 and 2001 was $1.189, $1.125, and $1.014, respectively.

The Utility is permitted by the State of South Dakota to burn some alternative fuels, including tire-derived fuel and biomass, at the Big Stone Plant. The quantity of alternative fuel burned at the Big Stone Plant is insignificant when compared to the total annual coal consumption at the Big Stone Plant.

General Regulation

The Utility is subject to regulation of rates and other matters in each of the three states in which it operates and by the federal government for certain interstate operations. A breakdown of electric rate regulation by each jurisdiction is as follows:

		2003		2002	
Rates	**Regulation**	**% of Electric Revenues**	**% of kwh Sales**	**% of Electric Revenues**	**% of kwh Sales**
MN retail sales	MN Public Utilities Commission	30.2%	25.3%	35.8%	28.3%
ND retail sales	ND Public Service Commission	25.0	20.0	29.2	21.9
SD retail sales	SD Public Utilities Commission	5.0	4.2	5.8	4.5
Transmission & sales for resale	Federal Energy Regulatory Commission	39.8	50.5	29.2	45.3
		100.0%	100.0%	100.0%	100.0%

The Utility operates under approved retail electric tariffs in all three states it serves. The Utility has an obligation to serve any customer requesting service within its assigned service territory. Accordingly, the Utility has designed its electric system to provide continuous service at time of peak usage. The pattern of electric usage can vary dramatically during a 24-hour period and from season to season. The Utility’s tariffs provide for continuous electric service and are designed to cover the costs of service during peak times. To the extent that peak usage can be reduced or shifted to periods of lower usage, the cost to serve all customers is reduced. In order to shift usage from peak times, the Utility has approved tariffs in all three states for lower rates for residential demand control and controlled service, in Minnesota and North Dakota for real-time pricing, and in North Dakota and South Dakota for bulk interruptible rates. Each of these specialized rates is designed to improve efficient use of the Utility facilities, while encouraging use of cost-effective electricity instead of other fuels and giving customers more control over the size of their electric bill. In all three states, the Utility has approved tariffs which allow qualifying customers to release and sell energy back to the Utility when wholesale energy prices make such transactions desirable.

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

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

Minnesota: Under the Minnesota Public Utilities Act, the Utility is subject to the jurisdiction of the MPUC with respect to rates, issuance of securities, depreciation rates, public utility services, construction of major utility facilities, establishment of exclusive assigned service areas, contracts and arrangements with subsidiaries and other affiliated interests, and other matters. The MPUC has the authority to assess the need for large energy facilities and to issue or deny certificates of need, after public hearings, within six months of an application to construct such a facility. The Utility has not had a significant rate proceeding before the MPUC since July 1987.

The Department of Commerce (DOC) is responsible for investigating all matters subject to the jurisdiction of the DOC or the MPUC, and for the enforcement of MPUC orders. Among other things, the DOC is authorized to collect and analyze data on energy and the consumption of energy, develop recommendations as to energy policies for the governor and the legislature of Minnesota and evaluate policies governing the establishment of rates and prices for energy as related to energy conservation. The DOC acts as a state advocate in matters heard before the MPUC. The DOC also has the power, in the event of energy shortage or for a long-term basis, to prepare and adopt regulations to conserve and allocate energy.

Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. The DOC may require the utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such DOC orders are appealable to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. Since 1995, the Utility has recovered demand-side management related costs not included in base rates under Minnesota's Conservation Improvement Programs through the use of an annual recovery mechanism approved by the MPUC.

The MPUC requires the submission of a 15-year advance integrated resource plan by utilities serving at least 10,000 customers, either directly or indirectly, and having at least 100 megawatts of load. The MPUC's findings and orders with respect to these submissions are binding for jurisdictional utilities. Typically, the filings are submitted every two years. The Utility's most recent plan was submitted to the MPUC in 2002 and was approved early in 2003. The MPUC also granted the Utility a one-year waiver in submitting its next integrated resource plan, which will be completed in 2005.

The MPUC requires the annual filing of a capital structure petition. In this filing the MPUC reviews and approves the capital structure for the Company. Once the petition is approved, the Company may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved capital structure petition. The Company's current capital structure petition is in effect until March 31, 2004. The Company filed its capital structure petition for 2004 on February 13, 2004 and is awaiting action from the MPUC.

The Minnesota legislature has enacted a statute that favors conservation over the addition of new resources. In addition, it has mandated the use of renewable resources where new supplies are needed, unless the utility proves that a renewable energy facility is not in the public interest. It has effectively prohibited the building of new nuclear facilities. An existing environmental externality law requires the MPUC, to the extent practicable, to quantify the environmental costs of each type of generation, and to use such monetized values in evaluating resource plans. The MPUC must disallow any nonrenewable rate base additions (whether within or outside of the state) or any rate recovery therefrom, and may not approve any nonrenewable energy facility in an integrated resource plan, unless the utility proves that a renewable energy facility is not in the public interest. The state has prioritized the acceptability of new generation with wind and solar ranked first and coal and nuclear ranked fifth, the lowest ranking.

Pursuant to the Minnesota Power Plant Siting Act, the Minnesota Environmental Quality Board (EQB) has been granted the authority to regulate the siting in Minnesota of large electric power generating facilities in an orderly manner compatible with environmental preservation and the efficient use of resources. To that end, the EQB is empowered, after study, evaluation and hearings, to select or designate sites in Minnesota for new electric power generating plants (50,000 kw or more) and routes for transmission lines (100 kv or more) and to certify such sites and routes as to environmental compatibility.

The Minnesota Legislature enacted the Minnesota Energy Security and Reliability Act in 2001. Its primary focus was to streamline the siting and routing processes for the construction of new electric generation and transmission projects. The bill also added to utility requirements for renewable energy and energy conservation.

North Dakota: The Utility is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities and other matters. The NDPSC periodically performs audits of gas and electric utilities over which it has rate setting jurisdiction to determine the reasonableness of overall rate levels. In the past, these audits have occasionally resulted in settlement agreements adjusting rate levels for the Utility. The North Dakota Energy Conversion and Transmission Facility Siting Act grants the NDPSC the authority to approve sites in North Dakota for large electric generating facilities and high voltage transmission lines. This Act is similar to the Minnesota Power Plant Siting Act described above and applies to proposed new electric power generating plants of 50,000 kw or more and proposed new transmission lines of more than 115 kv. The Utility is required to submit a ten-year plan to the NDPSC annually.

On December 29, 2000 the NDPSC approved a performance-based ratemaking (PBR) plan that links allowed earnings in North Dakota to seven performance standards in the areas of price, electric service reliability, customer satisfaction and employee safety. The PBR plan is effective for 2001 through 2005, unless suspended or terminated by the NDPSC or the Utility. This PBR plan provides the opportunity for the Utility to raise its allowed rate of return and share income with customers when earnings exceed the allowed return. During 2001, the Utility achieved a rate of return on equity that exceeded targets under the plan, resulting in a sharing of the income between shareholders and customers in the form of a $662,300 refund to North Dakota retail electric customers in 2002. Because the Utility’s 2002 rate of return was within the allowable range defined in the plan, no sharing occurred in 2003. The Utility’s 2003 rate of return is expected to be within the allowable range defined in the plan.

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

South Dakota: The South Dakota Public Utilities Act subjects the Utility to the jurisdiction of the SDPUC with respect to rates, public utility services, establishment of assigned service areas and other matters. The Utility is not currently subject to the jurisdiction of the SDPUC with respect to the issuance of securities. Under the South Dakota Energy Facility Permit Act, the SDPUC has the authority to approve sites in South Dakota for large energy conversion facilities (100,000 kw or more) and transmission lines of 115 kv or more. There have been no significant rate proceedings in South Dakota since November 1987.

FERC: Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935, as amended (FPA). The FERC is an independent agency which has jurisdiction over rates for electricity sales for resale, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one-day suspension period, subject to ultimate approval by the FERC. The Utility is a member of the Mid-Continent Area Power Pool (MAPP), which operates in parts of eight states in the Upper Midwest and in three provinces in Canada. Power pool sales are conducted continuously through MAPP in accordance with schedules filed by MAPP with the FERC. Additional MAPP functions include a regional reliability council that maintains generation reserve sharing requirements.

The Utility agreed in October 2001 to join the Midwest Independent System Operator (MISO) regional transmission organization (RTO) pursuant to FERC Order No. 2000. In December 2001, the MISO received FERC approval as a regional transmission organization. FERC’s view is that the MISO will benefit the public interest by enhancing the reliability of the Midwest electric grid and facilitating and enhancing wholesale competition. The MISO covers a broad region containing all or parts of 20 states and one Canadian province. The MISO began operational control of the Utility’s transmission facilities above 100 kv on February 1, 2002, but the Utility continues to own and maintain its transmission assets. As the transmission provider and security coordinator for the region, the MISO offers available capacity, accepts schedules and provides settlement for transmission services.

In July 2002, the FERC issued a Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD). Its purpose is to insure standard commercial rules for the operation of competitive markets for electricity. The SMD NOPR calls for markets to be operational across the United States by the end of 2004. In 2003 SMD met significant political resistance. As a result, FERC published a Wholesale Market Platform (WMP) white paper that provides for regional flexibility and state regulator involvement through Regional State Committees (RSCs). The MISO, with strong FERC encouragement, had established the end of 2003 as a target for MISO markets to be operational within its geographical area of operation. In July 2003, the MISO filed its proposed Transmission and Energy Markets Tariff (TEMT). In October 2003, the MISO withdrew its TEMT. The MISO has stated its plans to refile its TEMT in March of 2004. The MISO is proposing an operational date of December 1, 2004. The MISO is working together with the FERC on this process and has requested assurances from FERC that all start-up costs will be recoverable for market participants. As the Utility transitions to the full operation of the MISO there could be short-term negative impacts on wholesale power transactions.

Other: The Utility is subject to various federal and state laws, including the Federal Public Utility Regulatory Policies Act and the Energy Policy Act of 1992, which are intended to promote the conservation of energy and the development and use of alternative energy sources. The Utility may also become subject to comprehensive energy legislation currently pending before the United States Congress.

The Utility is unable to predict the impact on its operations resulting from future regulatory activities, from future legislation or from future tax that may be imposed on the source or use of energy.

Competition, Deregulation and Legislation

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

The Company believes the Utility is well positioned to be successful in a more competitive environment. A comparison of the Utility's electric retail rates to the rates of other investor-owned utilities, cooperatives and municipals in the states the Utility serves indicates that the Utility's rates are competitive. In addition, the Utility would attempt more flexible pricing strategies under an open, competitive environment.

Legislative and regulatory activity could affect operations in the future. The Utility cannot predict the timing or substance of any future legislation or regulation. State and federal efforts to restructure the electric utility industry have slowed. The United States Congress ended its 2003 legislative session without passing electric industry restructuring legislation or a comprehensive energy bill. There was no legislative action in 2003 regarding electric retail choice in any of the states where the Utility operates and no major electricity legislation is expected in 2004 legislative sessions in those states. The Company does not expect retail competition to come to the States of Minnesota, North Dakota or South Dakota in the foreseeable future.

Environmental Regulation

Impact of Environmental Laws: The Utility's existing generating plants are subject to stringent federal and state standards and regulations regarding, among other things, air, water and solid waste pollution. The Utility estimates it has expended in the five years ended December 31, 2003 approximately $6.4 million for environmental control facilities. Included in the 2004-2008 construction budget are approximately $6 million for environmental equipment for existing and new facilities, including $1.1 million for 2004.

Air Quality: Pursuant to the Federal Clean Air Act of 1970 as amended (the Act), the United States Environmental Protection Agency (EPA) has promulgated national primary and secondary standards for certain air pollutants.

The primary fuels burned by the Utility's steam generating plants are North Dakota lignite coal and western subbituminous coal. Electrostatic precipitators have been installed at the principal units at the Hoot Lake Plant. A fabric filter to collect particulates from stack gases has been installed on a smaller unit at Hoot Lake Plant. As a result, the units at the Hoot Lake Plant currently meet all presently applicable federal and state air quality and emission standards.

The Utility improved the fine particulate emissions control at Big Stone Plant by replacing a major portion of the plant's electrostatic precipitator in the third quarter of 2002. The replacement technology is an Advanced Hybrid technology that was installed as part of a demonstration project co-funded by the Department of Energy's National Energy Technology Laboratory Power Plant Improvement Initiative. The technology is designed to capture at least 99.99% of the fly ash particulates emitted from the boiler. Initial test data demonstrates the emissions design parameters were met, and follow-up emission testing is planned for 2004. However, the Department of Energy's National Energy Technology Laboratory, consultants, equipment vendors and the Utility jointly continue to investigate and assess the operational performance of the unit as well as options to improve the Advanced Hybrid's balance-of-plant impacts as part of an on-going effort to refine the demonstration technology.

The Big Stone Plant is currently operating within all presently applicable federal and state air quality and emission standards.

The Coyote Station is equipped with sulfur dioxide removal equipment. The removal equipment—referred to as a dry scrubber—consists of a spray dryer, followed by a fabric filter, and is designed to desulfurize hot gases from the stack. The fabric filter collects spray dryer residue along with the fly ash. The Coyote Station is currently operating within all presently applicable federal and state air quality and emission standards.

The Act, in addressing acid deposition, imposed requirements on power plants in an effort to reduce national emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x).

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

The national NO_x emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. Hoot Lake Plant unit 2 is governed by the phase one early opt-in provision until January 1, 2008. The remaining generating units meet the NO_x emission regulations that were adopted by the EPA in December 1996. All of the Utility's generating facilities met the NO_x standards during 2003.

The EPA Administrator signed the proposed Interstate Air Quality Rule on December 17, 2003. EPA has concluded that SO_2 and NO_x are the chief emissions contributing to interstate transport of particulate matter less than 2.5 microns ($PM_{2.5}$). EPA has also concluded that NO_x emissions are the chief emissions contributing to ozone non-attainment. Plans are to finalize the rule by mid-2005. Twenty-eight states and the District of Columbia were found to contribute 0.15 micrograms per cubic meter or more to ambient air quality $PM_{2.5}$ non-attainment in downwind states. On that basis, EPA is proposing to cap SO_2 and NO_x emissions in the designated states. Minnesota is included among the 28 states for emissions caps. Twenty-five states were found to contribute to downwind 8-hour ozone non-attainment. None of the states in the Utilities service territory are slated for NO_x reduction for ambient air quality 8-hour ozone non-attainment purposes, although EPA is proposing further study of the contributions from the North Dakota and South Dakota. The Utility is evaluating the proposal and is unable to assess its impact until the final rule promulgation.

The Act calls for EPA studies of the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and submitted reports to Congress. The Act required the EPA to make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced that it affirmatively decided to regulate mercury emissions from electric generating units. The EPA published the proposed mercury rule on January 30, 2004. The proposal included two options for regulating mercury emission from coal-fired electric generating units. One option would set technology-based maximum achievable control technology standards under paragraph 111(d) of the Act. The other option embodies a market-based cap and trade approach to emissions reduction. The Utility is currently evaluating the proposal. The EPA expects to issue final rules by December 2004. Because promulgation of rules by the EPA has not been completed, it is not possible to assess to what extent this regulation will impact the Utility.

In 1998, the EPA announced its New Source Review Enforcement Initiative targeting coal-fired utilities, petroleum refineries, pulp and paper mills and other industries for alleged violations of EPA's New Source Review rules. These rules require owners or operators that construct new major sources or make major modifications to existing sources to obtain permits and install air pollution control equipment at affected facilities. The EPA is attempting to determine if emission sources violated certain provisions of the Act by making major modifications to their facilities without installing state-of-the-art pollution controls. On January 2, 2001, the Utility received a request from the EPA, pursuant to Section 114(a) of the Act, to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. The Utility responded to that request. In March 2003 the EPA conducted a review of the plant's outage records as a follow-up to their January 2001 data request. A copy of the designated documents was provided to EPA on March 21, 2003. At this time the Utility cannot determine what, if any, actions will be taken by the EPA. The EPA issued changes to the existing New Source Review rules with respect to routine maintenance and repair and replacement activities in its Equipment Replacement Provision Rule on October 27, 2003. However, the U.S. Court of Appeals for the D.C Circuit issued an order which stayed the effective date of the Equipment Replacement Provision rule pending judicial review. The Utility is awaiting the Court's decision on the challenges to the rule, which is expected in 2005.

The Coyote Station is subject to certain emission limitations under the "Prevention of Significant Deterioration" (PSD) program of the Act. The EPA and the North Dakota Department of Health reached an agreement to identify a process for resolving several issues relating to the modeling protocol for the state's PSD program. A cap on the SO2 emissions could be imposed on all the coal-fired steam-electric generating units that are located in North Dakota, including the Coyote Station, as a result of the modeling effort. If a cap were imposed, it is likely the cap would be set at a level above current actual emission levels. The impact of a cap on SO2 emissions on future operations, if it were imposed, is uncertain.

The Dakota Resource Council filed a civil action against the EPA asking that the Court order EPA to perform the alleged non-discretionary duty of requiring the State of North Dakota to take steps to remedy alleged unlawful levels of SO2 in Theodore Roosevelt National Park, Lostwood Wilderness Area, Medicine Lakes Wilderness Area, and Fort Pect Indian Reservation. The Utility has joined with other North Dakota utilities in a Motion to Intervene in this proceeding.

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

On February 16, 2004, the EPA Administrator signed the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. The rule becomes effective 60 days after its publication in the *Federal Register.* The Utility is currently evaluating the impact of the rule on its facilities.

The Utility has all federal and state water permits presently necessary for the operation of the Coyote Station, the Big Stone Plant and the Hoot Lake Plant. The Utility owns five small dams on the Otter Tail River, which are subject to FERC licensing requirements. A license for all five dams was issued on December 5, 1991. Total nameplate rating (manufacturer's expected output) of the five dams is 3,450 kw.

Solid Waste: Permits for disposal of ash and other solid wastes have been issued for the Coyote Station, the Big Stone Plant and the Hoot Lake Plant. The Utility completed construction on the first cell of the new ash disposal site at Hoot Lake Plant in 2003, and it is available for use when the existing disposal area is filled later in 2004.

At the request of the Minnesota Pollution Control Agency (MPCA), the Utility has an ongoing investigation at its former, closed Hoot Lake Plant ash disposal sites. The MPCA continues to monitor site activities under their Voluntary Investigation and Cleanup Program. In April 2001, the Utility submitted a Remedial Investigation Work Plan to the MPCA describing its plan to further investigate the environmental impact of the closed portion of the Hoot Lake Plant ash disposal site. The MPCA approved the plan, with some suggested modifications, in July 2001. These tasks have been completed. The MPCA also asked that the Utility eliminate a ground water seepage that was originating from one of the disposal areas. Site work related to that request was completed in November 2001. However, seepage reappeared in a new location in the spring of 2002. The Utility initiated additional studies to further characterize the site and its report was submitted to the MPCA in March 2003 for their review and comment. The MPCA approved portions of the remediation measures that the Utility proposed and those were implemented in 2003. Although the Utility is still evaluating various options, its preliminary estimate of remediation costs to address the ash disposal site issues over the next three years is not expected to have a material impact on the Company’s consolidated net income, financial position or cash flows.

The EPA has promulgated various solid and hazardous waste regulations and guidelines pursuant to, among other laws, the Resource Conservation and Recovery Act of 1976, the Solid Waste Disposal Act Amendments of 1980 and the Hazardous and Solid Waste Amendments of 1984, which provide for, among other things, the comprehensive control of various solid and hazardous wastes from generation to final disposal. The States of Minnesota, North Dakota and South Dakota have also adopted rules and regulations pertaining to solid and hazardous waste. The total impact on the Utility of the various solid and hazardous waste statutes and regulations enacted by the federal government or the States of Minnesota, North Dakota and South Dakota is not certain at this time. To date, the Utility has incurred no significant costs as a result of these laws.

In 1980, the United States enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly known as the Federal Superfund law, which was reauthorized and amended in 1986. In 1983, Minnesota adopted the Minnesota Environmental Response and Liability Act, commonly known as the Minnesota Superfund law. In 1988, South Dakota enacted the Regulated Substance Discharges Act, commonly known as the South Dakota Superfund law. In 1989, North Dakota enacted the Environmental Emergency Cost Recovery Act. Among other requirements, the federal and state acts establish environmental response funds to pay for remedial actions associated with the release or threatened release of certain regulated substances into the environment. These federal and state Superfund laws also establish liability for cleanup costs and damage to the environment resulting from such release or threatened release of regulated substances. The Minnesota Superfund law also creates liability for personal injury and economic loss under certain circumstances. The Utility is unable to determine the total impact of the Superfund laws on its operations at this time but has not incurred any significant costs to date related to these laws. The Utility is not presently named as a potentially responsible party under the federal or state Superfund laws.

Capital Expenditures

The Utility is continually expanding, replacing and improving its electric facilities. During 2003, approximately $28.2 million was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2003 gross electric property additions, including construction work in progress, were approximately $161.1 million and gross retirements were approximately $53.2 million.

The Utility estimates that during the five-year period 2004-2008 it will invest approximately $132 million for electric construction. The Utility continuously reviews options for increasing its generating capacity. At this time the Utility has no firm plans for additional base load generating plant construction. The majority of electric utility expenditures for the five-year period 2004 through 2008 will be for work related to the Utility's production plants and distribution system.

Franchises

At December 31, 2003 the Utility had franchises to operate as an electric utility in all of the 371 incorporated municipalities that it serves. All franchises are nonexclusive and generally were obtained for 20-year terms, with varying expiration dates. No franchises are required to serve unincorporated communities in any of the three states that the Utility serves. There are 19 franchises that are set to expire during 2004. The Utility believes that these franchises will be renewed.

Employees

At December 31, 2003 the Utility had approximately 667 full-time employees. A total of 354 employees are represented by local unions of the International Brotherhood of Electrical Workers and are covered by a three-year labor contract expiring November 1, 2005. The Utility has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

PLASTICS

General

Plastics consists of businesses producing polyvinyl chloride (PVC) and polyethylene (PE) pipe. The Company derived 11% of its consolidated operating revenues from this segment in 2003, 13% in 2002, and 11% in 2001.

The following is a brief description of these businesses:

Northern Pipe Products, Inc., located in Fargo, ND, manufactures and sells PVC and PE pipe for municipal water, rural water, wastewater and other uses in the Northern, Midwestern and Western regions of the United States as well as Canada. During 2003, a 45,000-square-foot plant was opened in Hampton, IA for the production of corrugated PE pipe used in drainage and sewer systems.

Vinyltech Corporation, located in Phoenix, AZ, manufactures and sells PVC pipe for municipal water, wastewater, water reclamation systems and other uses in the Western, Southwest and South Central regions of the United States.

Together these companies have the capacity to produce approximately 200 million pounds of PVC and PE pipe annually.

Customers

The PVC and PE pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for the PVC and PE pipe products consist primarily of wholesalers and distributors throughout the Upper Midwest, Southwest and Western United States.

Competition

The plastic pipe industry is highly competitive, due to a relatively small number of producers, an even smaller number of raw material suppliers and the commodity nature of the product. Because of shipping costs, competition is usually regional in scope, instead of national.

Northern Pipe and Vinyltech compete not only against other plastic pipe manufacturers, but also ductile iron, steel, concrete and clay pipe producers. Pricing pressure will continue to affect operating margins in the future.

Northern Pipe and Vinyltech intend to continue to compete on the basis of their high quality products, cost-effective production techniques and close customer relations and support.

Manufacturing and Resin Supply

PVC pipe is manufactured through a process known as extrusion. During the production process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is then pulled through a series of water cooling tanks, marked to identify the type of pipe and cut to finished lengths. Warehouse and outdoor storage facilities are used to store the finished product. Inventory is shipped from storage to customers mainly by common carrier.

The PVC resins are acquired in bulk and shipped to point of use by rail car. Over the last ten years, there has been consolidation in PVC resin producers. There are a limited number of third party vendors that supply the PVC resin used by Northern Pipe and Vinyltech. During 2003, three vendors supplied the resin used, with over 96% of the resin purchased from two main vendors. During 2002, seven vendors supplied the resin used, with over 58% of the resin purchased from two main vendors. In 2001, two vendors provided approximately 75% of the PVC resin used. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could disrupt the ability of the Plastics segment to manufacture products, cause customers to cancel orders or require incurrence of additional expenses to obtain PVC resin from alternative sources, if such sources were available. Both Northern Pipe and Vinyltech believe they have good relationships with their key raw material vendors.

Due to the commodity nature of PVC resin and PVC pipe and the dynamic supply and demand factors worldwide, historically the markets for both PVC resin and PVC pipe have been very cyclical with significant fluctuations in prices and gross margins.

Capital Expenditures

Capital expenditures in the Plastics segment typically include investments in extrusion machines, land and buildings and management information systems. During 2003, capital expenditures of approximately $3.9 million were made in the Plastics segment. The 2003 expenditures relate to the opening of the new PE plant in Hampton, IA. Total capital expenditures during the five-year period 2004-2008 are estimated to be approximately $12 million.

Employees

At December 31, 2003 the Plastics segment had approximately 178 full-time employees.

MANUFACTURING

General

Manufacturing consists of businesses in the following manufacturing activities: production of waterfront equipment, wind towers, frame-straightening equipment and accessories for the auto body shop industry, custom plastic pallets, material and handling trays and horticultural containers; fabrication of steel products; contract machining; and metal parts stamping and fabrication.

The Company derived 24% of its consolidated operating revenues from this segment in 2003, 22% in 2002 and 21% in 2001. The following is a brief description of each of these businesses:

BTD Manufacturing, Inc. (BTD), located in Detroit Lakes and Pelican Rapids, MN, is a metal stamping and tool and die manufacturer that provides its services mainly to customers in the Midwest. BTD stamps, fabricates, welds and laser cuts metal components according to manufacturers' specifications primarily for the recreation vehicle, gas fireplace, health and fitness and enclosure industries.

Chassis Liner Corporation, located in Alexandria and Lucan, MN, manufactures and markets vehicle frame-straightening equipment and accessories used by the auto repair industry throughout the United States.

DMI Industries, Inc., located in West Fargo, ND, engineers and manufactures wind towers and other heavy metal fabricated products throughout the United States.

ShoreMaster, Inc., located in Fergus Falls, MN, along with its wholly owned subsidiary, Galva Foam Marine, Inc. located in Camdenton, MO, produces residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems that are marketed throughout the United States.

St. George Steel Fabrication, Inc., located in St. George and Salt Lake City, UT, fabricates structural steel members for buildings and bridges, ductwork for the power and refining industries, conveyors and hoppers for mining and industrial markets and plate steel products for the wind tower industry, primarily for customers in the Western United States.

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

Competition

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

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

Some of the products sold by the companies in the Manufacturing segment are purchased by companies in the recreational vehicle, wind energy and auto repair markets. A downturn in these markets could have an adverse impact on the financial results of the Company's Manufacturing segment.

Steel Supply

Many of companies in the Manufacturing segment use a variety of steel in the products that they manufacture. Steel prices have increased significantly due to a number of factors including demand from China's expanding economy, elevated energy prices that increase the cost of making steel, a shortage of coke (a substance made from coal that is used in making steel) and the falling dollar increasing the cost of imported steel. Both pricing and availability are concerns of steel users. Some steel companies are adding surcharges to offset their higher costs. The companies in the Manufacturing segment will attempt to pass the surcharges on to their customers. The increase in steel prices could have a negative affect on profit margins in the Manufacturing segment.

Legislation

The failure of Congress to pass a broad energy bill in 2003 and extend the Production Tax Credit could have an unfavorable impact on the Company's operations that manufacture towers for the wind energy industry.

Capital Expenditures

Capital expenditures in the Manufacturing segment typically include additional investments in new manufacturing equipment or expenditures to replace worn-out manufacturing equipment. Capital expenditures may also be made for the purchase of land and buildings for plant expansion and for investments in management information systems. During 2003, capital expenditures of approximately $9.9 million were made in the Manufacturing segment. Total capital expenditures for the Manufacturing segment during the five-year period 2004-2008 are estimated to be approximately $43 million.

Employees

At December 31, 2003 the Manufacturing segment had approximately 1,067 full-time employees.

HEALTH SERVICES

General

Health Services consists of the DMS Health Group, which includes businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide service maintenance, mobile diagnostic imaging, mobile positron emission tomography and nuclear medicine imaging, portable X-ray imaging and rental of diagnostic medical imaging equipment.

During 2003, two small acquisitions were completed in this segment, Topline Medical, Inc. and North Star Medical Systems, Inc. These companies sell cardiac patient monitoring equipment to healthcare facilities in the Upper Midwest.

The Company derived 13% of its consolidated operating revenues from this segment in 2003 and 14% in 2002 and 2001. The companies comprising the DMS Health Group include:

DMS Health Technologies, Inc. (DMS), located in Fargo, ND, sells, services and refurbishes diagnostic medical imaging equipment, patient monitoring equipment and related supplies and accessories. DMS sells radiology equipment primarily manufactured by Philips Medical Systems (Philips), a large multi-national company based in the Netherlands. Philips manufactures fluoroscopic, radiographic and mammography equipment, along with ultrasound, computerized tomography (CT) scanners, magnetic resonance imaging (MRI) scanners and cardiac cath labs. In December 2003 the Company's dealership agreement with Philips was renewed. DMS is also a supplier of medical film and related accessories. DMS markets mainly to hospitals, clinics and mobile service companies in North Dakota, South Dakota, Minnesota, Montana and Wyoming.

DMS Imaging, Inc., a subsidiary of DMS Health Technologies, Inc. located in Minneapolis, MN, operates mobile and in-house diagnostic medical imaging equipment, including CT, MRI, positron-emission tomography (PET), nuclear medicine services and other similar radiology services to hospitals, clinics, long-term care facilities and other medical providers located in 42 states. Regional offices are located in Houston, TX; Minneapolis, MN; and Sioux Falls, SD. DMS Imaging provides services in four different business units:

- DMS Imaging - provides shared diagnostic medical imaging services (primarily mobile) for MRI, CT, nuclear medicine, PET, ultrasound, mammography and bone density analysis.
- DMS Interim Solutions - offers interim and rental options for diagnostic imaging services.
- DMS MedSource Partners - develops partnerships with healthcare providers to offer dedicated in-house diagnostic imaging services, such as MRI.
- DMS Portable X-Ray - delivers portable X-ray, ultrasound and electrocardiogram services to nursing homes and other facilities.

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

Regulation

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

The federal Anti-Kickback Act prohibits persons from knowingly and willfully soliciting, receiving, offering or providing remuneration, directly or indirectly, to induce the referral of an individual or the furnishing or arranging for a good or service for which payment may be made under a federal healthcare program such as Medicare or Medicaid. Several states have similar statutes. The term “remuneration” has been broadly interpreted to include anything of value, including, for example, gifts, discounts, credit arrangements, payments of cash, waiver of payments and ownership interests. Penalties for violating the Anti-Kickback Act can include both criminal penalties and civil sanctions. By regulation, the U.S. Department of Health and Human Services has created certain “safe harbors” under the Act. These safe harbor regulations set forth certain provisions, which, if met, assure that healthcare providers will not be subject to liability under the Act.

The Ethics and Patient Referral Act of 1989 (the Stark Act) prohibits physician referrals of Medicare and Medicaid patients to an entity providing certain designated health services, including services provided by the Health Services companies. The Stark Act also prohibits an entity from billing for prohibited services. A person who engages in a scheme to violate the Stark Act or a person who presents a claim to Medicare or Medicaid in violation of the Stark Act may be subject to civil fines and possible exclusion from participation in federal healthcare programs.

The Health Services companies believe their operations comply with the Anti-Kickback Act and the Stark Act. However, if the Health Services companies were to engage in conduct in violation of these statutes, the sanction imposed could adversely affect the Company’s consolidated financial results.

The Health Insurance Portability and Accountability Act of 1996 (HIPAA) created federal crimes related to healthcare fraud and to making false statements related to healthcare matters. HIPAA prohibits knowingly and willfully executing a scheme to defraud any healthcare benefit program including a program involving private payors. Further, HIPAA prohibits knowingly and willfully falsifying, concealing or covering up a material fact or making any materially false statement in connection with the delivery of or payment for healthcare benefits or services. A violation of HIPAA is a felony and may result in fines, imprisonment or exclusion from government-sponsored programs such as Medicare and Medicaid. Finally, HIPAA creates federal privacy standards for individually identifiable health information and computer security standards for all health information. These standards became applicable in 2003 and the Health Services companies believe that they are in compliance with the requirements of HIPAA. However, if the Health Services companies were to engage in conduct in violation of these statutes, the sanction imposed could adversely affect the Company’s financial results.

In some states a certificate of need or similar regulatory approval is required prior to the acquisition of high-cost capital items or services, including diagnostic imaging systems or provisions of diagnostic imaging services by companies or its customers. Certificate of need laws were enacted to contain rising healthcare costs by preventing unnecessary duplication of health resources. Certificate of need regulations may limit or preclude the Health Services companies from providing diagnostic imaging services or systems. Conversely, a repeal of existing certificate of need regulations in states where the Health Services companies have obtained certificates of need could adversely affect their financial performance.

The Health Services companies continue to monitor developments in healthcare law and modify their operations from time to time as the business and regulatory environment changes. However, there can be no assurances that the Health Services companies will always be able to modify their operations to address changes in the regulatory environment without any adverse effect to their financial performance.

Reimbursement

The companies in the Health Services segment derive most of their revenues directly from healthcare providers rather than third-party payors, such as Medicare, Medicaid or private health insurance companies. The Health Services’ customers who are healthcare providers receive the majority of their payments from third-party payors. Payments by third-party payors depend upon their customers’ health insurance policies. Because unfavorable reimbursement policies have limited and may continue to limit the profit margins of hospitals and clinics the Health Services companies bill directly, it may be necessary to lower fees to retain existing customers and attract new ones.

Competition

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

Environmental, Health or Safety Laws

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

Capital Expenditures

Capital expenditures in this segment principally relate to the acquisition of diagnostic imaging equipment used in the imaging business. During 2003, capital expenditures of approximately $5.4 million were made in the Health Services segment. Total capital expenditures during the five-year period 2004-2008 are estimated to be approximately $5 million. Operating leases are also used to finance the acquisition of medical equipment used by Health Services companies. Current operating lease commitments during the five-year period 2004-2008 are estimated to be $46 million.

Employees

At December 31, 2003 the Health Services segment had approximately 410 full-time employees.

OTHER BUSINESS OPERATIONS

General

Other Business Operations consists of businesses engaged in electrical and telephone construction contracting, specialty contracting including design-and-build services for new construction, transportation, telecommunications, energy services and natural gas marketing as well as the portion of corporate general and administrative expenses that are not allocated to the other segments.

On November 1, 2003 the Company acquired the assets and operations of Foley Company.

The Company derived 16% of its consolidated operating revenues from these businesses in 2003 and 13% in 2002 and 14% in 2001. Following is a brief description of each of these businesses.

Foley Company, headquartered in Kansas City, MO, provides mechanical and prime contracting services including design-and-build services for new construction, retrofitting, process piping, equipment settings and instrumentation and control systems. Major clients include water and wastewater treatment plants, power generation plants, hospital and pharmaceutical facilities, power generation plants and other industrial and manufacturing projects across a multi-state service area in the Central United States.

Midwest Construction Services, Inc., located in Moorhead, MN, is a holding company for five subsidiaries that provide electrical design and construction services for the industrial, commercial and municipal business markets, including government, institutional, communications, utility and renewable energy projects in the Upper Midwest.

Midwest Information Systems, Inc., headquartered in Parkers Prairie, MN, provides telephone, cable and internet services with over 10,000 access lines for phone, internet and cable television to homes in rural western Minnesota communities through its subsidiaries: Midwest Telephone Company, Osakis Telephone Company, Peoples Telephone Company of Big Fork and Data Video Systems, Inc.

Otter Tail Energy Services Company, headquartered in Fergus Falls, MN, was established in 1997 to provide unregulated energy-based products and services to commercial, industrial and institutional clients throughout the Upper Midwest. During 2003 operations within this company were scaled back to providing technical and engineering services, energy efficient lighting, and retail marketing of natural gas and energy management services to 150 customers in Iowa, South Dakota, North Dakota and Minnesota.

E. W. Wylie Corporation (Wylie), located in Fargo, ND, is a contract and common carrier operating a fleet of tractors and trailers in 48 states and 6 Canadian provinces. Wylie has trucking terminals in Fargo, ND, Des Moines, IA, Fort Worth, TX, and Chicago, IL.

Regulation

The telephone subsidiaries are subject to the regulatory authority of the MPUC regarding rates and charges for telephone services, as well as other matters. The telephone subsidiaries must keep on file with the MPUC schedules of such rates and charges, and any requests for changes in such rates and charges must be filed with the MPUC for approval. The telephone industry is also subject generally to rules and regulations promulgated by the Federal Communications Commission. The cable television subsidiary is regulated by federal and local authorities.

Competition

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

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

Capital Expenditures

Capital expenditures in this segment typically include investments in additional trucks and flat bed trailers, construction equipment and infrastructure to support the telephone, cable and internet services. During 2003, capital expenditures of approximately $3.2 million were made in Other Business Operations. Capital expenditures during the five-year period 2004-2008 are estimated to be approximately $16 million for Other Business Operations. The majority of the capital expenditures in the five-year period 2004-2008 will be used to replace existing equipment mainly in the telecommunication and construction companies.

Employees

At December 31, 2003 there were approximately 408 full-time employees in Other Business Operations. 105 employees of Moorhead Electric, Inc. are represented by local unions of the International Brotherhood of Electrical Workers and were covered by a two-year labor contract that expired May 31, 2003. Provisions exist under the labor contract that extended that contract until May 31, 2004. Moorhead Electric, Inc. has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

Forward Looking Information - Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

In connection with the “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995 (the Act), the Company has filed cautionary statements identifying important factors that could cause the Company’s actual results to differ materially from those discussed in forward-looking statements made by or on behalf of the Company. When used in this Form 10-K and in future filings by the Company with the Securities and Exchange Commission, in the Company’s press releases and in oral statements, words such as “may”, “will”, “expect”, “anticipate”, “continue”, “estimate”, “project”, “believes” or similar expressions are intended to identify forward-looking statements within the meaning of the Act and are included, along with this statement, for purposes of complying with the safe harbor provision of the Act. Factors that might cause such differences include, but are not limited to, the Company’s diversification efforts, growth of electric revenues, the timing and scope of deregulation and open competition, Federal Energy Regulatory Commission mandated operational changes to the electricity transmission grid, impact of the investment performance of the Utility’s pension plan, changes in the economy, weather conditions, market valuation of forward energy contracts, availability of resin suppliers, resin prices, steel prices, governmental and regulatory action, fuel and purchased power costs, environmental issues, and other factors discussed under “Critical Accounting Policies Involving Significant Estimates” and “Factors Affecting Future Earnings” on pages 24 through 27 of the Company’s 2003 Annual Report to Shareholders, filed as an Exhibit hereto. These factors are in addition to any other cautionary statements, written or oral, which may be made or referred to in connection with any such forward-looking statement or contained in any subsequent filings by the Company with the Securities and Exchange Commission.

Item 2. PROPERTIES

The Coyote Station, which commenced operation in 1981, is a 414,000 kw (nameplate rating) mine-mouth plant located in the lignite coal fields near Beulah, North Dakota and is jointly owned by the Utility, Northern Municipal Power Agency, Montana-Dakota Utilities Co. and Northwestern Public Service Company. The Utility owns 35% of the plant and on July 1, 1998 became the operating agent of the Coyote Station.

The Utility, jointly with Northwestern Public Service Company and Montana-Dakota Utilities Co., owns the 414,000 kw (nameplate rating) Big Stone Plant in northeastern South Dakota which commenced operation in 1975. The Utility is the operating agent of Big Stone Plant and owns 53.9% of the plant.

Located near Fergus Falls, Minnesota, the Hoot Lake Plant is comprised of three separate generating units with a combined nameplate rating of 127,000 kw. The oldest Hoot Lake Plant generating unit was constructed in 1948 (7,500 kw nameplate rating) and a subsequent unit was added in 1959 (53,500 kw nameplate rating). A third unit was added in 1964 (66,000 kw nameplate rating) and later modified during 1988 to provide cycling capability, allowing this unit to be more efficiently brought online from a standby mode.

At December 31, 2003 the Utility's transmission facilities, which are interconnected with lines of other public utilities, consisted of 48 miles of 345 kv lines; 404 miles of 230 kv lines; 728 miles of 115 kv lines; and 4,108 miles of lower voltage lines, principally 41.6 kv. The Utility owns the uprated portion of the 48 miles of the 345 kv line, with Minnkota Power Cooperative retaining title to the original 230 kv construction.

In addition to the properties mentioned above, the Company owns and has investments in offices and service buildings. The Company's subsidiaries own facilities and equipment used to manufacture PVC pipe and perform metal stamping, fabricating and contract machining; construction equipment and tools; medical imaging equipment; a fleet of flatbed trucks and trailers and the infrastructure to maintain approximately 10,000 access lines for phone, internet and cable television in its telecommunication companies.

Management of the Company believes the facilities and equipment described above are adequate for the Company's present businesses. In the fall of 2003, NorthWestern Corporation, which is the owner of Northwestern Public Service Company, filed for bankruptcy and is in the process of restructuring. The Company does not currently expect that these events will have a material adverse affect on the operation of the Coyote Station or the Big Stone Plant.

All of the common shares of the companies owned by Varistar are pledged to secure indebtedness of Varistar.

Item 3. LEGAL PROCEEDINGS

Not Applicable.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the three months ended December 31, 2003.

Item 4A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF MARCH 1, 2004)

Set forth below is a summary of the principal occupations and business experience during the past five years of the executive officers as defined by rules of the Securities and Exchange Commission. Except as noted below, each of the executive officers has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly owned subsidiary, Varistar.

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE
John D. Erickson (45)	4/8/02	Present: President and Chief Executive Officer
	4/9/01	President
	4/10/00	Executive Vice President, Chief Financial Officer and Treasurer
	Prior to 4/10/00	Vice President, Finance and Chief Financial Officer

NAME AND AGE	DATES ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE
George A. Koeck (51)	4/10/00	Present: Corporate Secretary and General Counsel
	8/2/99	General Counsel
	Prior to 8/2/99	Partner, Dorsey & Whitney LLP
Lauris N. Molbert (46)	6/10/02	Present: Executive Vice President and Chief Operating Officer
	4/9/01	Executive Vice President, Corporate Development and Varistar President and Chief Operating Officer
	4/10/00	Vice President, Chief Operating Officer, Varistar; President and Chief Operating Officer, Varistar
	Prior to 4/10/00	President and Chief Operating Officer, Varistar
Kevin G. Moug (44)	4/9/01	Present: Chief Financial Officer and Treasurer
	Prior to 4/9/01	Varistar Chief Financial Officer and Treasurer
Charles S. MacFarlane (39)	5/1/03	President, Otter Tail Power Company
	6/1/02	Interim President, Otter Tail Power Company
	1/29/02	Director, Finance & Strategic Planning Otter Tail Power Company
	12/1/01	Director, Finance Planning Otter Tail Power Company
	Prior to 12/2/01	Director, Electric Distribution Planning, Engineering & Reliability, Xcel Energy

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

PART II

Item 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The information required by this Item is incorporated by reference to the first sentence under "Otter Tail Corporation Stock Listing" on Page 53, to "Selected Consolidated Financial Data" on Page 17 and to "Quarterly Information" on Page 49 of the Company's 2003 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 6. SELECTED FINANCIAL DATA

The information required by this Item is incorporated by reference to "Selected Consolidated Financial Data" on Page 17 of the Company's 2003 Annual Report to Shareholders, filed as an Exhibit hereto.

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

The information required by this Item is incorporated by reference to "Management's Discussion and Analysis of Financial Condition and Results of Operations" on Pages 18 through 30 of the Company's 2003 Annual Report to Shareholders, excluding "Report of Management" and "Independent Auditors' Report on Page 30, filed as an Exhibit hereto.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this Item is incorporated by reference to "Quantitative and Qualitative Disclosures About Market Risk" on Pages 28 and 29 of the Company's 2003 Annual Report to Shareholders, filed as an Exhibit hereto.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this Item is incorporated by reference to "Quarterly Information" on Page 49, the Company's audited financial statements on Pages 31 through 49 and "Independent Auditors' Report" on page 30 of the Company's 2003 Annual Report to Shareholders, filed as an Exhibit hereto.

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

None.

Item 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15 (e) under the Securities Exchange Act of 1934) as of December 31, 2003, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2003.

During the fiscal quarter ended December 31, 2003 there were no changes in the Company's internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this Item regarding Directors is incorporated by reference to the information under “Election of Directors” in the Company’s definitive Proxy Statement dated March 17, 2004. The information regarding executive officers is set forth in Item 4A hereto. The information regarding Section 16 reporting is incorporated by reference to the information under “Section 16(a) Beneficial Ownership Reporting Compliance” in the Company’s definitive Proxy Statement dated March 17, 2004. The information regarding Audit Committee financial experts and identification of the Audit Committee is incorporated by reference to the information under “Meetings and Committees of the Board - Audit Committee” in the Company’s definitive Proxy Statement dated March 17, 2004.

The Company has adopted a code of conduct that applies to all of its directors, officers (including its principal executive officer, principal financial officer, principal accounting officer or controller or person performing similar functions) and employees. The Company’s code of conduct is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 10 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of conduct by posting such information on its website at the address specified above. Information on the Company’s website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

The information regarding shareholder nominating procedures is incorporated by reference to the information under “Meetings and Committees of the Board - Corporate Governance Committee” in the Company’s definitive Proxy Statement dated March 17, 2004.

Item 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under “Summary Compensation Table,” “Options/SAR Grants in Last Fiscal Year,” “Aggregated Option/SAR Exercises in Last Fiscal Year and Fiscal Year-End Options/SAR Values,” “Pension and Supplemental Retirement Plans,” “Severance and Employment Agreements,” and “Director Compensation” in the Company’s definitive Proxy Statement dated March 17, 2004.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The security ownership information set forth under “Outstanding Voting Shares” and “Management’s Security Ownership” in the Company’s definitive Proxy Statement dated March 17, 2004 is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2003 about the Company's common stock that may be issued under all of its equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders			
1999 Stock Incentive Plan	1,531,125	$25.16	621,598(1)
1999 Employee Stock Purchase Plan	—	N/A	165,037(2)
Equity compensation plans not approved by security holders	—	—	—
Total	1,531,125	$25.16	786,635

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

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

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under "Approval of Auditors" in the Company's definitive Proxy Statement dated March 17, 2004.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) List of documents filed:

(1) and (2) See Table of Contents on Page 29 hereof.

(3) See Exhibit Index on Pages 30 through 36 hereof.

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

(b) Reports on Form 8-K:

The Company filed a Form 8-K on November 5, 2003 to furnish under Item 12 the press release issued on November 3, 2003 to report its earnings for the third quarter of 2003.

SIGNATURES

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

OTTER TAIL CORPORATION
By /s/ Kevin G. Moug

Kevin G. Moug
Chief Financial Officer
and Treasurer

Dated: March 12, 2004

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

Signature and Title		
John D. Erickson President and Chief Executive Officer (principal executive officer)	)	
Kevin G. Moug Chief Financial Officer and Treasurer (principal financial and accounting officer)	)	By /s/ John D. Erickson
John C. MacFarlane Chairman of the Board and Director	)	John D. Erickson Pro Se and Attorney-in-Fact Dated March 12, 2004
Karen M. Bohn, Director	)	
Thomas M. Brown, Director	)	
Dennis R. Emmen, Director	)	
Arvid R. Liebe, Director	)	
Kenneth L. Nelson, Director	)	
Nathan I. Partain, Director	)	
Gary J. Spies, Director	)	
Robert N. Spolum, Director	)	

OTTER TAIL CORPORATION

TABLE OF CONTENTS

FINANCIAL STATEMENTS, SUPPLEMENTARY FINANCIAL DATA, SUPPLEMENTAL FINANCIAL SCHEDULES INCLUDED IN ANNUAL REPORT (FORM 10-K) FOR THE YEAR ENDED DECEMBER 31, 2003

The following items are included in this annual report by reference to the registrant's Annual Report to Shareholders for the year ended December 31, 2003:

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

Exhibit Index
to
Annual Report
on Form 10-K
For Year Ended December 31, 2003

	Previously Filed		
	File No.	**As Exhibit No.**	
3-A	8-K dated 4/10/01	3	—Restated Articles of Incorporation, as amended (including resolutions creating outstanding series of Cumulative Preferred Shares).
3-C	33-46071	4-B	—Bylaws as amended through April 11, 1988.
4-D-1	8-A dated 1/28/97	1	—Rights Agreement, dated as of January 28, 1997 (the Rights Agreement), between the Company and Norwest Bank Minnesota, National Association.
4-D-2	8-A/A dated 9/29/98	1	—Amendment No. 1, dated as of August 24, 1998, to the Rights Agreement.
4-D-3	10-K for year ended 12/31/01	4-D-7	—Note Purchase Agreement dated as of December 1, 2001.
4-D-4	10-K for year ended 12/31/02	4-D-4	—First Amendment dated as of December 1, 2002 to Note Purchase Agreement dated as of December 1, 2001.
4-D-5	333-90952	99-A-1	—Credit Agreement dated as of April 30, 2002.
4-D-6	8-K dated 9/27/02	99-A	—First Amendment dated as of September 19, 2002 to Credit Agreement dated as of April 30, 2002.
4-D-7	10-Q for quarter ended 6/30/03	4-A	—Second Amendment dated as of April 29, 2003 to Credit Agreement dated as of April 30, 2002.
4-D-8	10-Q for quarter ended 9/30/03	4.1	—Third Amendment dated as of August 25, 2003 to Credit Agreement dated as of April 30, 2002.
10-A	2-39794	4-C	—Integrated Transmission Agreement dated August 25, 1967, between Cooperative Power Association and the Company.

Table of Contents

	Previously Filed		
	File No.	As Exhibit No.	
10-A-1	10-K for year ended 12/31/92	10-A-1	—Amendment No. 1, dated as of September 6, 1979, to Integrated Transmission Agreement, dated as of August 25, 1967, between Cooperative Power Association and the Company.
10-A-2	10-K for year ended 12/31/92	10-A-2	—Amendment No. 2, dated as of November 19, 1986, to Integrated Transmission Agreement between Cooperative Power Association and the Company.
10-C-1	2-55813	5-E	—Contract dated July 1, 1958, between Central Power Electric Corporation, Inc., and the Company.
10-C-2	2-55813	5-E-1	—Supplement Seven dated November 21, 1973. (Supplements Nos. One through Six have been superseded and are no longer in effect.)
10-C-3	2-55813	5-E-2	—Amendment No. 1 dated December 19, 1973, to Supplement Seven.
10-C-4	10-K for year ended 12/31/91	10-C-4	—Amendment No. 2 dated June 17, 1986, to Supplement Seven.
10-C-5	10-K for year ended 12/31/92	10-C-5	—Amendment No. 3 dated June 18, 1992, to Supplement Seven.
10-C-6	10-K for year ended 12/31/93	10-C-6	—Amendment No. 4 dated January 18, 1994, to Supplement Seven.
10-D	2-55813	5-F	—Contract dated April 12, 1973, between the Bureau of Reclamation and the Company.
10-E-1	2-55813	5-G	—Contract dated January 8, 1973, between East River Electric Power Cooperative and the Company.
10-E-2	2-62815	5-E-1	—Supplement One dated February 20, 1978.
10-E-3	10-K for year ended 12/31/89	10-E-3	—Supplement Two dated June 10, 1983.
10-E-4	10-K for year ended 12/31/90	10-E-4	—Supplement Three dated June 6, 1985.

	Previously Filed		
	File No.	As Exhibit No.	
10-E-5	10-K for year ended 12/31/92	10-E-5	—Supplement No. Four, dated as of September 10, 1986.
10-E-6	10-K for year ended 12/31/92	10-E-6	—Supplement No. Five, dated as of January 7, 1993.
10-E-7	10-K for year ended 12/31/93	10-E-7	—Supplement No. Six, dated as of December 2, 1993.
10-F	10-K for year ended 12/31/89	10-F	—Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and North-western Public Service Company (dated as of January 7, 1970).
10-F-1	10-K for year ended 12/31/89	10-F-1	—Letter of Intent for pur-chase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-F-2	10-K for year ended 12/31/91	10-F-2	—Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-F-3	10-K for year ended 12/31/91	10-F-3	—Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-F-4	10-K for year ended 12/31/91	10-F-4	—Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-F-5	10-Q for quarter ended 9/30/03	10.1	—Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-F-6	10-K for year ended 12/31/92	10-F-5	—Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-G	10-Q for quarter ended 09/30/01	10-B	—Big Stone Plant Coal Agreements by and between the Company, Northwestern Public Service, Montana-Dakota Utilities Co., and RAG Coal West, Inc. (dated as of September 28, 2001).

	Previously Filed		
	File No.	As Exhibit No.	
10-H	2-61043	5-H	—Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company, and Minnesota Power & Light Company (dated as of July 1, 1977).
10-H-1	10-K for year ended 12/31/89	10-H-1	—Supplemental Agreement No. One dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-2	10-K for year ended 12/31/89	10-H-2	—Supplemental Agreement No. Two dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement.
10-H-3	10-K for year ended 12/31/89	10-H-3	—Amendment dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-4	10-K for year ended 12/31/92	10-H-4	—Agreement dated as of Sept. 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No.1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978.
10-H-5	10-Q for quarter ended 9/30/01	10-A	—Amendment dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-H-6	10-Q for quarter ended 9/30/03	10.2	—Amendment dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-I	2-63744	5-I	—Coyote Plant Coal Agreement by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company, Minnesota Power & Light Company, and Knife River Coal Mining Company (dated as of January 1, 1978).

	Previously Filed		
	File No.	As Exhibit No.	
10-I-1	10-K for year ended 12/31/92	10-I-1	—Addendum, dated as of March 10, 1980, to Coyote Plant Coal Agreement.
10-I-2	10-K for year ended 12/31/92	10-I-2	—Amendment (No. 3), dated as of May 28, 1980, to Coyote Plant Coal Agreement.
10-I-3	10-K for year ended 12/31/92	10-I-3	—Fourth Amendment, dated as of August 19, 1985, to Coyote Plant Coal Agreement.
10-I-4	10-Q for quarter ended 6/30/93	19-A	—Sixth Amendment, dated as of February 17, 1993, to Coyote Plant Coal Agreement.
10-I-5	10-K for year ended 12/31/01	10-I-5	—Agreement and Consent to Assignment of the Coyote Plant Coal Agreement.
10-K	10-K for year ended 12/31/91	10-K	—Diversity Exchange Agreement by and between the Company and Northern States Power Company, (dated as of May 21, 1985) and amendment thereto (dated as of August 12, 1985).
10-K-1	10-Q for quarter ended 9/30/99	10	—Power Sales Agreement between the Company and Manitoba Hydro Electric Board (dated as of July 1, 1999).
10-L	10-K for year ended 12/31/91	10-L	—Integrated Transmission Agreement by and between the Company, Missouri Basin Municipal Power Agency and Western Minnesota Municipal Power Agency (dated as of March 31, 1986).
10-L-1	10-K for year ended 12/31/88	10-L-1	—Amendment No. 1, dated as of December 28, 1988, to Integrated Transmission Agreement (dated as of March 31, 1986).
10-M	10-K for year ended 12/31/99	10-M	—Hoot Lake Coal Transportation Agreement by and between the Company and The Burlington Northern and Santa Fe Railway Company (dated as of July 19, 1999).
10-N-1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended.*
10-N-2	10-Q for quarter ended 3/31/02	10-C	—Executive Survivor and Supplemental Retirement Plan, as amended.*

	Previously Filed		
	File No.	As Exhibit No.	
10-N-3	10-K for year ended 12/31/93	10-N-5	—Nonqualified Profit Sharing Plan.*
10-N-4	10-Q for quarter ended 3/31/02	10-B	—Nonqualified Retirement Savings Plan, as amended.*
10-N-5	10-K for year ended 12/31/98	10-N-6	—1999 Employee Stock Purchase Plan.
10-N-6	10-K for year ended 12/31/98	10-N-7	—1999 Stock Incentive Plan.*
10-O-1	10-Q for quarter ended 6/30/02	10-A	—Executive Employment Agreement, John Erickson.*
10-O-2	10-Q for quarter ended 6/30/02	10-B	—Executive Employment Agreement and amendment no. 1, Lauris Molbert.*
10-O-3	10-Q for quarter ended 6/30/02	10-C	—Executive Employment Agreement, Kevin Moug.*
10-O-4	10-Q for quarter ended 6/30/02	10-D	—Executive Employment Agreement, George Koeck.*
10-P-1	10-Q for quarter ended 6/03/02	10-E	—Change in Control Severance Agreement, John Erickson.*
10-P-2	10-Q for quarter ended 6/03/02	10-F	—Change in Control Severance Agreement, Lauris Molbert.*
10-P-3	10-Q for quarter ended 6/03/02	10-G	—Change in Control Severance Agreement, Kevin Moug.*
10-P-4	10-Q for quarter ended 6/03/02	10-H	—Change in Control Severance Agreement, George Koeck.*
13-A			—Portions of 2003 Annual Report to Shareholders incorporated by reference in this Form 10-K.
21-A			—Subsidiaries of Registrant.
23			—Consent of Deloitte & Touche LLP.
24-A			—Powers of Attorney.
31.1			—Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2			—Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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

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

Section 2: EX-13.A (PORTIONS OF 2003 ANNUAL REPORT TO SHAREHOLDERS)

Selected Consolidated Financial Data

(thousands, except number of shareholders and per-share data)	2003	2002	2001	2000 (1)	1999 (1) (2)	1998 (3)	1993
Revenues							
Electric (7)	**$267,494**	$244,005	$232,720	$219,718	$203,393	$206,895	$180,912
Plastics	**86,009**	82,931	63,216	82,667	31,504	24,946	—
Manufacturing	**177,805**	142,390	123,436	97,506	87,086	62,488	8,473
Health services	**100,912**	93,420	79,129	66,319	68,805	69,412	32,068
Other business operations	**123,475**	84,627	80,667	78,159	68,322	48,829	32,396
Intersegment eliminations	**(2,456)**	(1,036)	—	—	—	—	—
Total operating revenues	**$753,239**	$646,337	$579,168	$544,369	$459,110	$412,570	$253,849
Special charges	**—**	—	—	—	—	9,522	—
Income from continuing operations	**39,656**	46,128	43,603	41,042	45,295	30,701	27,369
Cumulative change in accounting principle	**—**	—	—	—	—	3,819	—
Cash flow from operations	**76,955**	76,797	77,529	61,761	81,850	63,959	53,255
Capital expenditures	**50,734**	75,533	53,596	46,273	35,245	29,289	30,894
Total assets (6)	**986,423**	914,112	817,778	772,562	729,118	690,189	597,482
Long-term debt	**265,193**	258,229	227,360	195,128	180,159	181,046	166,563
Redeemable preferred	**—**	—	—	18,000	18,000	18,000	18,000
Basic earnings per share from continuing operations (4)	**1.52**	1.80	1.69	1.59	1.75	1.20	1.11
Diluted earnings per share from continuing operations (4)	**1.51**	1.79	1.68	1.59	1.75	1.20	1.11
Return on average common equity	**12.2%**	15.3%	15.5%	15.4%	18.4%	15.0%	14.9%
Dividends per common share	**1.08**	1.06	1.04	1.02	0.99	0.96	0.84
Dividend payout ratio	**72%**	59%	62%	64%	57%	71%	76%
Common shares outstanding — year end	**25,724**	25,592	24,653	24,574	24,571	23,759	22,360
Number of common shareholders (5)	**14,723**	14,503	14,358	14,103	13,438	13,699	13,634

Notes:

(1) Restated to reflect the effects of two 2001 acquisitions accounted for under the pooling-of-interests method. The impact of the poolings on years prior to 1999 is not material.

(2) 1999 results include the sale of radio station assets for a net gain of $8.1 million or 34 cents per share.

(3) In the first quarter of 1998 the Company changed its method of electric revenue recognition in the states of Minnesota and South Dakota from meter-reading dates to energy-delivery dates. Basic and diluted earnings per share from continuing operations does not include 16 cents per share related to the cumulative effect of the change in accounting principle.

(4) Based on average number of shares outstanding.

(5) Holders of record at year end.

(6) Prior years are restated to reflect reclassification of reserve for estimated removal costs from accumulated depreciation to a regulatory liability.

(7) Prior years are restated to reflect implementation of a new accounting standard, EITF Issue 03-11. See note 1 to consolidated financial statements for more information.

Management's Discussion and Analysis of
Financial Condition and Results of Operations

The primary financial goals of Otter Tail Corporation (the Company) are to maximize its earnings and cash flows and to allocate capital profitably toward growth opportunities that will increase shareholder value. Management meets these objectives by earning the returns regulators allow in electric operations combined with growing nonelectric operations. Meeting these objectives enables the Company to preserve and enhance its financial capability by maintaining optimal capitalization ratios and a strong interest coverage position, and preserving strong credit ratings on outstanding securities, which in the form of lower interest rates benefits both the Company's customers and shareholders.

Liquidity

The Company believes its financial condition is strong and that its cash, other liquid assets, operating cash flows, access to capital markets and borrowing ability because of strong 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. However, the Company's operating cash flow and access to capital markets can be impacted by macroeconomic factors outside its control. In addition, the Company's borrowing costs can be impacted by its short-term and long-term debt ratings assigned by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The Company has achieved a high degree of long-term liquidity by maintaining desired capitalization ratios and strong credit ratings, implementing cost-containment programs, and investing in projects that provide returns in excess of the Company's weighted average cost of capital.

Cash provided by operating activities of $77.0 million for the year ended December 31, 2003 combined with cash on hand of $9.9 million at December 31, 2002 allowed the Company to pay dividends and finance all of its capital expenditures in 2003.

Cash provided by operating activities in 2003 was $77.0 million compared with $76.8 million in 2002. The slight increase in cash from operations includes a $7.0 million increase in noncurrent liabilities and deferred credits and a $3.3 million increase in noncash depreciation and amortization expense offset by a $6.5 million decrease in net income and a $4.5 million increase in cash used for working capital items.

The $19.2 million decrease in net cash used in investing activities between 2003 and 2002 reflects a decrease in capital expenditures of $24.8 million and $1.6 million in cash from redemption of other investments offset by a $6.3 million increase in cash used to complete acquisitions and a $0.8 million decrease in cash from disposal of assets. The decrease in consolidated capital expenditures reflects a high level of capital expenditures in 2002, a year that saw major plant additions and equipment purchases in all segments including the electric utility's expenditures for a new transmission line completed in 2002 and a new gas-fired combustion turbine that came online in June 2003.

In 2003, the Company completed three acquisitions: Two medical equipment companies were purchased for an aggregate of $1.9 million in cash. In November 2003, the Company acquired the assets and operations of Foley Company, a mechanical and prime contracting firm based in Kansas City, Missouri, for $12.3 million in cash.

Net cash used in financing activities was $19.2 million in 2003 compared with $1.4 million provided by financing activities in 2002. The $20.6 million decrease between the years is due to the following:

- Net short-term borrowings were $25.5 million less in 2003 than in 2002.
- Net proceeds from the issuance and retirement of long-term debt, including debt issuance expenses, were $8.4 million higher in 2003 than in 2002.
- Proceeds from employee stock plans decreased by $2.0 million in 2003 compared to 2002 due to a 64% reduction in the number of stock options exercised in 2003.
- Dividends paid and other distributions increased by $1.5 million in 2003.

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 note bears interest at a variable rate of 3-month LIBOR plus 1.43% on the unpaid principal balance. The Company used proceeds from the note to pay down borrowings under the Company's line of credit that were used to finance acquisitions and capital expenditures of its nonelectric subsidiaries. The covenants associated with the note are consistent with existing credit facilities. There are no rating triggers associated with this note.

During 2003, 47,552 shares of common stock were issued for stock options exercised under the 1999 Stock Incentive Plan generating proceeds of $1.0 million. Also in 2003, in noncash transactions, the Company granted 90,900 shares of restricted stock to certain key executives and directors and issued 2,169 common shares for director compensation under the 1999 Stock Incentive Plan.

Capital Requirements

The Company has a capital expenditure program for the expansion, upgrade and improvement of its plants and operating equipment. Typical uses of cash for capital improvements are investments in electric generation facilities, transmission and distribution lines, equipment used in the manufacturing process, acquisitions 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, the costs of labor, materials and equipment, and the Company's consolidated financial condition.

Consolidated capital expenditures for the years 2003, 2002 and 2001 were $50.7 million, $75.5 million and $53.6 million, respectively. The estimated capital expenditures for 2004 are $40.8 million and the total capital expenditures for the five-year period 2004 through 2008 are estimated to be approximately $208 million.

(side-by-side bar graph of data with cash realization ratio data labels in the following table)

CASH REALIZATION RATIOS
(millions)

	2001	2002	2003
Cash flows from operations	$ 78	$ 77	$ 77
Net income	$ 44	$ 46	$ 40
Cash realization ratios	178%	166%	194%

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

(end of graph)

(stacked bar graph of data with interest-bearing debt as a percent of total capital data labels in the following table)

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

	2001	2002	2003
Total capital	$551	$625	$654
Interest-bearing debt (includes short-term debt)	$256	$296	$305
Interest-bearing debt as a percent of total capital	46%	47%	47%

(end of graph)

The breakdown of 2001, 2002 and 2003 actual and 2004 through 2008 estimated capital expenditures by segment is as follows:

	2001	2002	2003	2004	2004-2008
			(in millions)		
Electric	$35	$46	$28	$27	$132
Plastics	2	6	4	2	12
Manufacturing	11	15	10	5	43
Health services	3	4	6	3	5
Other business operations	3	5	3	4	16
Total	$54	$76	$51	$41	$208

The following table summarizes the Company’s contractual obligations at December 31, 2003 and the effect these obligations are expected to have on its liquidity and cash flow in future periods.

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(in millions)		
Long-term debt	$275	$ 10	$22	$ 51	$192
Coal contracts (required minimums)	86	29	11	11	35
Capacity and energy requirements	147	17	30	30	70
Other purchase obligations	3	3	—	—	—
Operating leases	65	21	30	10	4
Total contractual cash obligations	$576	$ 80	$93	$102	$301

Capital Resources

Financial flexibility is provided by unused lines of credit, strong financial coverages and credit ratings, and alternative financing arrangements such as leasing.

For the period 2004 through 2008, the Company estimates that funds internally generated net of forecasted dividend payments, combined with funds on hand, will be sufficient to meet scheduled debt retirements, provide for its estimated consolidated capital expenditures and pay off its currently outstanding short-term debt. Reduced demand for electricity, reductions in wholesale sales of electricity or margins on wholesale sales, or declines in the number of products manufactured and sold by the Company could have an effect on funds internally generated. Additional short-term or long-term financing will be required in the period 2004 through 2008 in the event the Company decides to refund or retire early any of its 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 the Company. If adequate funds are not available on acceptable terms, the Company’s business, results of operations, and financial condition could be adversely affected.

In order to maintain a balanced capital structure consistent with the risk profile of the Company's diversified mix of businesses, the Company began issuing new shares of common stock in January 2004 to meet the requirements of its dividend reinvestment program and share purchase plan rather than purchasing shares on the open market. The Company estimates this change will generate approximately $9 million in equity funding in 2004.

The Company has the ability to issue up to an additional $135 million of unsecured debt securities from time to time under its shelf registration statement on file with the SEC.

On August 25, 2003 the Company's line of credit was increased from $50 million to $70 million. This line is available to support borrowings of the Company's nonelectric operations. The Company anticipates the electric utility's cash requirements will be provided for by cash flows from electric utility operations. This line bears interest at the rate of LIBOR plus 0.5% and expires on April 28, 2004. The Company does not anticipate any difficulties in renewing this line of credit. The Company's 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. The Company's obligations under this line of credit are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company's nonelectric companies. As of December 31, 2003, $30 million of the $70 million line was in use and the Company had $7.3 million in cash and cash equivalents.

The Company's line of credit, its $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. As of December 31, 2003 the Company was in compliance with all of the covenants under its financing agreements.

The interest rate under the line of credit is subject to adjustment in the event of a change in ratings on the Company's senior unsecured debt, up to LIBOR plus 0.8% if the ratings on the Company's senior unsecured debt fall to BBB+ or below (Standard & Poor's) or Baa1 or below (Moody's). The line of credit also provides for accelerated repayment in the event the Company's long-term senior unsecured debt is rated below BBB- (Standard & Poor's) or Baa3 (Moody's).

On September 18, 2003 Standard & Poor's Ratings Services lowered its rating on the Company's senior unsecured debt from A to A-, lowered its rating on the Company's preferred stock from A- to BBB and changed its outlook on the Company from stable to negative. According to Standard & Poor's, the rating action reflects the Company's increased business risk profile due to the increasing size of its nonelectric businesses and concerns associated with the future financial performance of the Company's manufacturing and health services segments. The ratings changes did not require any action under rating triggers and did not increase interest rates on current outstanding debt.

The Company's securities ratings at December 31, 2003 are:

	Moody's Investors Service	**Standard & Poor's**
Senior unsecured debt	A2	A-
Preferred stock	Baa1	BBB
Outlook	Negative	Negative

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

The Company’s 6.63% senior notes contain an investment grade put that could require the Company to prepay this series with a make-whole premium if the Company’s senior unsecured debt is rated below Baa3 (Moody’s) or BBB- (Standard & Poor’s). The Company’s obligations under the 6.63% senior notes are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company’s nonelectric companies. The Company’s Grant County and Mercer County pollution control refunding revenue bonds require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, 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). The Company believes the risk of the downgrade events described in this paragraph occurring is remote based on the current debt ratings of the Company combined with its strong debt-to-equity ratio and ability to generate cash from operations.

(bar graph of data in the following table)

LONG-TERM DEBT INTEREST COVERAGE
(times interest earned before tax)

2001	2002	2003
5.2	5.1	4.4

(end of graph)

The Company’s ratio of earnings to fixed charges was 3.5x for 2003 compared to 3.9x for 2002 and its long-term debt interest coverage ratio before taxes was 4.4x for 2003 compared to 5.1x for 2002. The main reason for the reduction in these coverage ratios is an $11.6 million reduction in income before interest and income taxes in 2003 compared to 2002. During 2004, the Company expects these coverage ratios to increase over 2003 levels if net income reaches management expectations.

Off-Balance-Sheet Arrangements

The Company does 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. The Company is not exposed to any financing, liquidity, market or credit risk that could arise if it had such relationships.

Results of Operations

Consolidated Results of Operations

The Company recorded diluted earnings per share of $1.51 for the year ended December 31, 2003 compared to $1.79 for the year ended December 31, 2002. Total operating revenues for 2003 were $753.2 million compared with $646.3 million for 2002. Operating income was $71.2 million for 2003 compared with $82.3 million for 2002.

Amounts presented in the following tables for 2003 and 2002 operating revenues, electric operation and maintenance expenses, cost of goods sold and nonelectric segment operating expenses will not agree with amounts presented in the Consolidated Statements of Income due to the elimination of intersegment transactions. The total intersegment eliminations include: $2,456,000 in operating revenues, $202,000 in electric operation and maintenance expenses, $495,000 in cost of goods sold and $1,759,000 in other nonelectric expenses in 2003; and $1,036,000 in operating revenues, $222,000 in electric operation and maintenance expenses, $446,000 in cost of goods sold and $368,000 in other nonelectric expenses in 2002. In 2001, intersegment eliminations were included in segment reporting due to immateriality.

Electric

Otter Tail Power Company, a division of Otter Tail Corporation, provides electrical service to more than 127,000 customers in a service territory exceeding 50,000 square miles.

In the third quarter of 2003, the electric utility began applying mark-to-market accounting to its forward contracts for the purchase or sale of energy that did not meet the definition of a capacity contract as a result of the issuance of Statement of Financial Accounting Standards (SFAS) No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. With the issuance of SFAS No. 149, any forward contracts for the purchase or sale of energy entered into after June 30, 2003 that do not meet the definition of a capacity contract and are subject to unplanned netting, referred to as a book out in the utility industry, are not eligible for the normal purchases and sales exception provided for under SFAS No. 133 and modified by SFAS No. 149.

In 2003, a consensus was reached on Emerging Issues Task Force (EITF) Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not “Held for Trading Purposes” as Defined in Issue No. 02-3. The reporting requirements of EITF Issue 03-11 are applicable to financial statement presentation in the fourth quarter of 2003. The Company determined that the net method of reporting was appropriate for the electric utility’s forward energy contracts. Revenue from the electric utility’s wholesale sales of energy purchased from other suppliers is now reflected net of the related purchase power costs in electric revenues on the Company’s consolidated statements of income for the years 2003, 2002 and 2001. The effects of the application of EITF Issue 03-11 and reclassification of prior years’ reported revenues are reflected in the table below. See note 1 to consolidated financial statements.

	2003	**2002**	**2001**
		(in thousands)	
Retail sales revenues	$217,611	$207,039	$199,262
Wholesale revenues:			
Sales off company-owned generation	18,428	11,941	13,760
Net margins on purchased power resold	9,045	6,354	9,495
Net unrealized marked-to-market gains	2,057	—	—
Other revenues	20,353	18,671	10,203
Total operating revenue	$267,494	$244,005	$232,720
Production fuel	51,163	44,122	41,776
Purchased power – retail use	36,002	30,915	24,527
Other operation and maintenance expenses	87,186	80,756	75,531
Depreciation and amortization	26,008	24,910	24,272
Property taxes	9,598	9,423	9,464
Operating income	$ 57,537	$ 53,879	$ 57,150

The increase of $10.6 million in retail revenue from 2002 to 2003 is mainly due to a $9.4 million increase in cost-of-energy (COE) revenue. The remaining increase in retail revenue was due to a 0.7% increase in retail kilowatt-hour (kwh) sales. The increase in retail sales reflects minor increases (less than 1%) in residential, commercial and industrial kwh sales. Heating-degree-days totaled 9,071 in 2003 compared with 9,033 in 2002 and were not a discernable factor contributing to 2003 sales variances. The increase in COE revenues reflects a 13.2% increase in fuel and purchased power costs per kwh for retail use in 2003 compared with 2002.

Wholesale revenue from sales of company-owned generation increased 54.3% in 2003 compared with 2002 due to a 19.6% increase in kwh sales combined with a 29.0% increase in revenue per kwh of generation sold. Gross margins on resales of purchased power increased 42.4% between 2003 and 2002 as a result of a 25.1% increase in kwh sales combined with a 14.1% increase in the margin per kwh resold. The 36.1% increase in overall wholesale electric prices reflects increased demand for electricity in the Mid-Continent Area Power Pool (MAPP) region. Higher prices in the wholesale power markets also reflect generally increasing generation costs, reduced generation from regional hydro facilities due to lower spring runoff and the lack of summer rainfall and high-cost generation from natural gas-fired peaking units. The higher prices combined with increased availability of electric utility-owned generation and well-timed energy purchases in 2003 compared to 2002 put the electric utility in a favorable position to respond to the increased demand for electricity resulting in the increase in wholesale electric sales. Wholesale revenue reflects $2.1 million in unrealized marked-to-market gains on forward energy contracts at year-end 2003.

Other electric operating revenues increased $1.7 million or 9.0% between 2003 and 2002. The increase reflects $2.5 million in increased transmission related revenues from control area services, transmission tariffs and shared use deficiency payments, and a $1.3 million increase in revenue from the sale of steam to an ethanol plant that began operations in the third quarter of 2002, offset by a $2.1 million reduction in revenue from contract work. Revenue from major projects included $7.6 million from regional wind generation projects in 2003 compared to $9.9 million from work on a North Dakota transmission line for another area utility that was completed in the fourth quarter of 2002.

The 16.0% increase in production fuel expense in 2003 compared with 2002 is due to an increase in fuel costs and generation at the electric utility's coal-fired generating stations, and an increase in fuel costs from combustion turbine generation. A 12.0% increase in the fuel cost per kwh generated reflects increases in fuel cost per kwh at all of the electric utility's generating units including fuel costs for the Company's new combustion turbine brought online in June 2003. The 16.5% increase in purchased power costs for retail use in 2003 compared with 2002 was the result of a 21.3% increase in the cost per kwh purchased offset by a 4.0% decrease in kwh purchases for retail use.

The 8.0% increase in other operation and maintenance expenses in 2003 compared with 2002 includes increased labor related expenses of $2.7 million as a result of annual wage increases of about 3.5% and increases in employee benefit costs. Pole maintenance and tree-trimming costs increased $1.0 million and transportation and travel-related expenses increased $1.0 million between the years. Insurance costs including provisions for damages were up $0.8 million. Fuel procurement costs increased $0.5 million, mainly related to litigation before the Surface Transportation Board. Uncollectible accounts expense increased $0.4 million.

The 4.4% increase in depreciation and amortization expense for 2003 compared to 2002 is due to an increase in depreciable plant base as a result of recent capital expenditures.

The Company expects the electric segment to have a solid year financially, but does not expect electric segment results in 2004 to equal those of 2003.

The $7.8 million increase in retail sales from 2001 to 2002 reflects increased usage by residential and commercial customers partially offset by a decrease in usage by industrial customers. Heating-degree-days totaled 9,033 in 2002 compared with 8,575 in 2001, an increase of 5.3%. An increase in COE revenues reflects an 11.5% increase in fuel and purchased power costs per kwh for system use in 2002 compared with 2001. Wholesale revenue from sales of company-owned generation decreased $1.8 million or 13.2% on a 3.0% decrease in kwhs sold and a 10.5% decrease in revenue per kwh of generation sold. Net margins on purchased power resold declined $3.1 million or 33.1% between 2002 and 2001 despite a 10.2% increase in kwh sales mainly as a result of a 39.2% decrease in the margin per kwh resold. The 23% decrease in overall wholesale electric prices may be partially attributable to peaking generation added in the MAPP region since September 2001, as well as lower regional demand for electricity. The increase in other electric operating revenues of $8.5 million is primarily due to revenue earned on a large transmission line construction project completed for another regional utility in 2002.

The 5.6% increase in production fuel expense in 2002 compared with 2001 is primarily due to a 13.7% increase in fuel costs per kwh produced at the electric utility's coal-fired generating stations. The increase in fuel costs per kwh produced is due to higher costs reflected in new coal contracts that went into effect at the beginning of 2002 and increased freight rates for the shipping of coal to Big Stone and Hoot Lake Plants. In 2001, coal was being shipped to Big Stone Plant under a negotiated agreement that expired at the end of 2001. Currently, coal is being shipped to Big Stone Plant under a tariff rate.

The 26.0% increase in purchased power costs for retail use in 2002 over 2001 was the result of a 52.6% increase in kwh purchases for retail use offset by a 17.4% decrease in the cost per kwh purchased. The volume of power purchased in 2002 increased for both system use and resale purposes. Purchased power for retail use increased to meet system demand and to replace the loss of generation at Big Stone Plant during six weeks of scheduled maintenance in the fall of 2002.

The 6.6% increase in other operation and maintenance expenses in 2002 compared with 2001 includes $3.8 million in material costs incurred in the construction of a transmission line for another regional utility and $2.0 million in increased employee benefit expenses offset by a $1.0 million decrease in external services expenses. The 2.6% increase in depreciation and amortization expense for 2002 compared to 2001 is due to an increase in the electric utility's composite depreciation rate from 3.06% in 2001 to 3.08% in 2002 and an increase in depreciable plant base as a result of recent capital expenditures.

Plastics

Plastics consists of businesses involved in the production of polyvinyl chloride (PVC) and polyethylene (PE) pipe in the Upper Midwest and Southwest regions of the United States.

	2003	**2002**	**2001**
		(in thousands)	
Operating revenues	$86,009	$82,931	$63,216
Cost of goods sold	76,046	65,628	57,932
Operating expenses	3,824	4,702	3,446
Depreciation and amortization	2,126	1,760	1,726
Amortization of goodwill	—	—	1,503
Operating income (loss)	$ 4,013	$10,841	$ (1,391)

Plastics operating revenues increased 3.7% in 2003 compared with 2002 due to an 8.2% increase in the average sales price per pound of pipe sold. The increase was partially offset by a 4.2% decrease in pounds sold between the years. The increased revenue was more than offset by a 15.9% increase in cost of goods sold reflecting a 20.9% increase in the average cost per pound of pipe sold. The average cost per pound of resin, the raw material used to produce PVC pipe, increased 26.3% between the periods. Operating expenses decreased 18.7% between the periods primarily due to decreased compensation directly related to the decrease in gross margins. The 20.8% increase in depreciation and amortization expense is related to a $4.4 million increase in depreciable plant in 2002 and a $3.5 million increase in depreciable plant in 2003.

The Company cannot predict if the tight operating margins experienced in the plastics segment in 2003 will continue into 2004. Gross margins generally decline when the supply of PVC pipe increases faster than demand. The gross margin percentage is sensitive to PVC raw material resin prices and the demand for PVC pipe. 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 assume that historical trends will continue.

The 31.2% increase in plastics operating revenues for 2002 compared with 2001 reflects a 23.0% increase in pounds of PVC pipe sold combined with a 6.6% increase in the average sales price per pound. The 13.3% increase in cost of goods sold reflects $14.6 million in costs related to the increase in PVC pipe sold offset by a $7.0 million reduction in costs due to a 7.0% decrease in the price per pound of PVC resin. Operating expenses increased 36.4% primarily due to increases in sales commissions and incentive compensation related to increased profitability in this segment. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

In 2003, 96.4% of raw material was purchased from two vendors. In 2002, 58.3% of raw material was purchased from two vendors and in 2001, 74.9% of raw material was purchased from two vendors. The Company believes relationships with their key raw material vendors are good. However, the loss of a key supplier or any interruption or delay in the supply of PVC resin could have a significant impact on the plastics segment.

Manufacturing

Manufacturing consists of businesses involved in the production of waterfront equipment, wind towers, frame-straightening equipment and accessories for the auto body shop industry, custom plastic pallets, material and handling trays and horticultural containers, fabrication of steel products, contract machining and metal parts stamping and fabricating. During 2002 and 2001 the following acquisitions were completed. See note 2 to consolidated financial statements.

Acquisition	Year Acquired	Business Combination
ShoreMaster,Inc.	May-02	Purchase
Galva Foam Marine Industries, Inc.	Oct-02	Purchase
T.O. Plastics, Inc.	Feb-01	Pooling of interests
St. George Steel Fabrication, Inc.	Sept-01	Pooling of interests
Titan Steel Corporation	Nov-01	Purchase

	2003	2002	2001
		(in thousands)	
Operating revenues	$177,805	$142,390	$123,436
Cost of goods sold	139,720	107,977	91,360
Operating expenses	22,244	18,411	14,762
Depreciation and amortization	7,708	6,525	4,858
Amortization of goodwill	—	—	281
Operating income	$ 8,133	$ 9,477	$ 12,175

The 24.9% increase in manufacturing operating revenues for 2003 compared with 2002 includes a $25.7 million increase in revenue from the waterfront equipment companies acquired in 2002. Revenues from the Company’s manufacturer of thermoformed plastic and horticultural products increased $8.0 million on an increase in the volume of products sold. Revenue at the metal parts stamping and fabrication company increased $3.0 million and the Company’s manufacturer of wind towers recorded $1.5 million in increased revenue. These increases were offset by decreases in revenue of $2.5 million from the manufacturer of structural steel products and $0.3 million from the manufacturer of automobile frame-straightening equipment.

The 29.4% increase in cost of goods sold in 2003 compared with 2002 primarily reflects a $19.1 million increase in costs of goods sold at the waterfront equipment companies combined with increased costs of $6.0 million at the Company’s manufacturer of wind towers mostly in material costs, $5.3 million from the Company’s manufacturer of thermoformed plastic and horticultural products related to increased sales, and $2.5 million from the metal parts stamping and fabrication company primarily related to material costs. These increases were offset by a reduction in cost of goods sold of $0.4 million at the manufacturer of structural steel products, mainly related to reduced labor expenses, and $0.1 million from the manufacturer of automobile frame-straightening equipment. The 18.1% increase in depreciation and amortization expense in 2003 compared with 2002 is due to 2002 and 2003 plant expansions and equipment purchases at all the manufacturing companies.

While the Company does not expect the business conditions that contributed to decreased earnings from the manufacturing segment in 2003 to continue in 2004, the uncertainty of the economy and the Production Tax Credit in the wind energy business, and the impact of steel pricing could adversely impact this segment’s performance in 2004.

The 15.4% increase in manufacturing operating revenues for 2002 compared with 2001 reflects the 2002 acquisitions of ShoreMaster and Galva Foam and increased production and sales of wind towers offset by decreased sales volumes of metal parts stamping and steel fabrication. Cost of goods sold increased 18.2% due to the ShoreMaster and Galva Foam acquisitions and increases of $9.3 million in material and subcontractor costs at the wind tower manufacturing business offset by a $4.8 million reduction in material costs at the metal parts stamping companies. The ShoreMaster and Galva Foam acquisitions accounted for $3.4 million of the $3.6 million increase in operating expenses between the periods and $0.4 million of the increase in depreciation and amortization expense. The remaining $1.3 million increase in depreciation and amortization expense in 2002 compared with 2001 is due to 2001 and 2002 plant expansions and equipment purchases at all the manufacturing companies. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

Health Services

Health services include businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment, and related supplies and accessories. In addition, these businesses also provide service maintenance, mobile diagnostic imaging, mobile PET and nuclear medicine imaging, portable x-ray imaging and rental of diagnostic medical imaging equipment. During 2003, 2002 and 2001 the following acquisitions were completed. See note 2 to consolidated financial statements.

Acquisition	Year Acquired	Business Combination
Topline Medical/North Star Medical Systems	May/July 2003	Purchase
Computed Imaging Service, Inc.	May-02	Purchase
Mobile Diagnostic Services, Inc.	Nov-02	Purchase
Interim Solutions/Midwest Medical Diagnostics	Sept-01	Purchase
Nuclear Imaging, Ltd.	Sept-01	Purchase

	2003	2002	2001
	(in thousands)		
Operating revenues	$100,912	$93,420	$79,129
Cost of goods sold	75,085	66,680	59,388
Operating expenses	15,442	13,676	9,362
Depreciation and amortization	5,137	4,410	2,912
Amortization of goodwill	—	—	605
Operating income	$ 5,248	$ 8,654	$ 6,862

The 8.0% increase in health services operating revenues for 2003 compared with 2002 reflects $6.7 million in additional scan and other services revenue, mostly from the acquisitions that occurred in 2002. Revenues from the sale of diagnostic imaging equipment increased $0.8 million between the periods in part due to recent acquisitions in 2003. The number of scans performed increased 12.6% mainly due to the 2002 acquisitions, while the average fee per scan decreased 1.8%.

Although revenues from imaging services increased by $6.7 million, the increase was more than offset by increases in equipment and infrastructure costs incurred to support expected revenue growth. While operating income for 2003 was significantly less than operating income in 2002, the segment’s 2003 results have improved significantly from early 2003 in part due to steps taken by management to address increases in operating expenses of the diagnostic imaging operations. The company that sells and services medical diagnostic and monitoring equipment had a good year financially, but the results from imaging services were disappointing, primarily due to aggressive growth combined with subsequent integration challenges. Management continues to address the cost structure of the diagnostic imaging operations and hired a new president/chief operating officer in the fourth quarter of 2003 to lead the imaging part of the health services segment. In December 2003, the DMS Health Group renewed its dealership agreement with Philips Medical Systems.

The 18.1% increase in health services operating revenues, 12.3% increase in cost of goods sold, 46.1% increase in operating expenses and 51.4% increase in depreciation and amortization for 2002 compared with 2001 are primarily due to the acquisitions completed during September 2001 and May 2002. The number of scans performed increased 19.8% due to the acquisitions while the average fee per scan increased 7.6% primarily as a result of the addition of new modalities provided by the companies acquired in September 2001. Revenues from equipment sales decreased 3.4%. Operating margins improved slightly between the periods due to increases in margins on service sales in the diagnostic equipment imaging business and in the mobile imaging business offset by expenses incurred in the segment's continued investment in and promotion of fixed-based imaging systems. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

Other Business Operations

The Company's other business operations include businesses involved in electrical and telephone construction contracting, specialty contracting including design and build services for new construction, transportation, telecommunications, entertainment, energy services, and natural gas marketing as well as the portion of corporate general and administrative expenses that are not allocated to the other segments. On November 1, 2003 the Company acquired the assets and operations of Foley Company (Foley), a mechanical and prime contracting firm based in Kansas City, Missouri. See note 2 to consolidated financial statements.

	2003	2002	2001
		(in thousands)	
Operating revenues	$123,475	$84,627	$80,667
Cost of goods sold	82,378	46,414	41,109
Operating expenses	39,885	33,739	30,927
Depreciation and amortization	4,983	5,008	5,093
Amortization of goodwill	—	—	850
Operating (loss) income	$ (3,771)	$ (534)	$ 2,688

The 45.9% increase in operating revenues in 2003 compared with 2002 was mostly due to a $13.8 million increase in revenues from natural gas sales at the Company's energy services company related to an increase in natural gas prices. In addition, construction revenues increased by $21.4 million, of which $7.9 million came from Foley, acquired in November 2003. Transportation revenues increased by $2.3 million between the periods as a result of an 85.6% increase in brokered miles. The 77.5% increase in cost of goods sold reflects a $14.4 million increase in the cost of natural gas sold by the energy services company and a $21.6 million increase in construction costs at the construction companies, of which $6.5 million is attributable to Foley.

The 18.2% increase in operating expenses between the periods reflects a $2.4 million increase in transportation operating expenses mainly related to increased brokerage activity. The construction companies reported $1.0 million in increased operating expenses with $0.5 million of the increase related to Foley. Operating expenses also reflect $3.3 million in increased operating expenses related to unallocated corporate overhead costs mainly due to increased employee benefit costs and increases in self-insurance costs. Operating expense at the energy services company decreased $1.9 million from 2002 to 2003 as a result of decreased activity. The Company had recorded $250,000 in goodwill related to the acquisition of an energy management firm in 2002. Based on an offer to purchase this entity in the fourth quarter of 2003, the Company determined that the goodwill related to this entity was impaired and, accordingly, recorded a $250,000 charge to operating income in the fourth quarter of 2003.

Construction margins have declined due to the sluggish economy and increased competition for available work. A decrease of $1.2 million in construction operating income was offset by a $1.3 million decrease in operating losses from the energy services company. The telecommunications company reported a 4.7% decrease in operating income in 2003. The transportation company's operating income increased by 6.1% in 2003 but it is still faced with continuing pressure on operating margins because of increased fuel and insurance costs and highly competitive pricing.

The 4.9% increase in operating revenues in the other business operations segment for 2002 compared with 2001 includes increases of $3.1 million at the energy services company, $1.6 million at the construction subsidiaries and $0.5 million in corporate services revenue, partially offset by a decrease in revenue of $1.2 million at the transportation subsidiary. The increase in operating revenue at the energy services company reflects increased revenue from natural gas sales and increased revenue from the installation of energy efficient lighting equipment on customer premises in 2002 compared with 2001. The increase in operating revenues at the construction subsidiaries reflects an increase in the volume of work performed in 2002 compared with 2001. A decrease of 6.1% in miles driven combined with a 2.4% decrease in revenue per mile led to the decrease in operating revenues at the transportation subsidiary.

The 12.9% increase in cost of goods sold in the other business operations segment for 2002 compared with 2001 includes increases in cost of goods sold of $3.8 million at the energy services company and $1.8 million at the construction subsidiaries that are directly related to increased revenues at those companies. Increased costs in excess of increased operating revenues due to smaller margins on natural gas sales and competition for fewer jobs in the construction segment related to the economic slowdown resulted in a $0.9 million decrease in operating margins at those companies from 2001 to 2002. Operating expenses increased 8.5% primarily due to a $1.5 million increase in unallocated corporate costs, a $1.1 million increase in operating expenses at the energy services company and a $337,000 increase in operating expenses at the telecommunications subsidiary mainly due to increases in their provisions for doubtful accounts related to the WorldCom and Global Crossings bankruptcies. A 5.0% decrease in the average cost of diesel fuel per gallon at the transportation subsidiary partially offset the increase in operating expenses at the other companies. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

The Company currently has $1.0 million of goodwill recorded on its balance sheet related to its energy services subsidiary that markets natural gas to approximately 150 retail customers. A recent evaluation of projected cash flows from this operation indicated that the related goodwill was not impaired. However, actual and projected cash flows from this operation are subject to fluctuations due to low profit margins on natural gas sales combined with high volatility of natural gas prices. Reductions in profit margins or the volume of natural gas sales could result in an impairment of all or a portion of its related goodwill. The Company will continue to evaluate this reporting unit for impairment on an annual basis and as conditions warrant.

The Company currently has $6.7 million of goodwill recorded on its balance sheet relating to the acquisition of E.W. Wylie Corporation (Wylie) its flatbed trucking company. Highly competitive pricing in the trucking industry in recent years has resulted in decreased operating margins and lower returns on invested capital for Wylie. The Company's current projections are for operating margins to increase from current levels over the next three to five years as demand for shipping increases relative to available shipping capacity and additional revenues are generated from added terminal locations. If current conditions persist and operating margins do not increase according to Company projections, the reductions in anticipated cash flows from transportation operations may indicate that the fair value of Wylie is less than its book value resulting in an impairment of goodwill and a corresponding charge against earnings. At December 31, 2003, assessment of Wylie indicated that its goodwill was not impaired. The Company will continue to evaluate this reporting unit for impairment on an annual basis and as conditions warrant.

Consolidated Interest Charges

As a result of lower variable interest rates, interest expense increased only $21,000 in 2003 compared to 2002. The average interest rate paid on short-term debt decreased from 2.2% in 2002 to 1.7% in 2003.

The $1.9 million (11.6%) increase in interest charges in 2002 over 2001 is due to higher long-term debt balances outstanding offset by lower interest rates on less short-term debt outstanding between the years. In late December 2001, the Company sold $90 million of 6.63% senior notes due 2011 and used part of the proceeds to retire $18 million of $6.35 cumulative preferred shares, $18 million of 8.75% first mortgage bonds due 2021, $17.3 million of subsidiary term debt and $20 million in short-term debt. The net impact of this refinancing resulted in additional interest expense from the additional long-term debt outstanding and the shift of $1.2 million from preferred dividend payments in 2001 to interest expense in 2002. Interest expense on short-term debt decreased from $1.0 million in 2001 to $0.3 million in 2002. The average daily short-term debt balance decreased from $16.7 million in 2001 to $13.2 million in 2002 and the average interest rate paid on short-term debt decreased from 5.2% in 2001 to 2.2% in 2002.

Consolidated Income Taxes

The Company’s effective tax rate was 27.4% for 2003 compared with 30.3% for 2002. The reduction reflects the impact of R&D tax credits claimed in 2003. Without these credits, the 2003 effective tax rate would have been 28.5%. The remaining 1.8% difference in the effective tax rate for 2003 compared to 2002 is a function of the level of fixed deductions and credits in proportion to lower net income before tax in 2003 compared to 2002. See note 13 to consolidated financial statements.

The Company’s effective tax rate was 30.3% for 2002 compared with 31.5% for 2001. Although net income before taxes was $2.5 million higher in 2002 than in 2001, income taxes remained essentially the same in both years. This reflects the discontinuance of goodwill amortization in 2002. The nontaxable portion of goodwill was $1.3 million in 2001. The tax reduction on the remaining $1.2 million in pre-tax income of approximately $0.5 million reflects a reduction of tax provisions related to the settlement of IRS audits of the Company’s 1997 and 1998 tax returns.

Impact of Inflation

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

The Company’s plastics, manufacturing, health services, and other business operations consist almost entirely of unregulated businesses. Increased operating costs are reflected in product or services pricing with any limitations on price increases determined by the marketplace. The impact of inflation on these segments has not been significant during the past few years because of the relatively low rates of inflation experienced in the United States. 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, with a possible adverse effect on the Company’s profitability, especially in high inflation periods where raw material and energy cost increases would lead finished product prices.

Factors Affecting Future Earnings

The results of operations discussed above are not necessarily indicative of future earnings. Factors affecting future earnings include, but are not limited to, the Company's diversification efforts, growth of electric revenues, the timing and scope of deregulation and open competition, Federal Energy Regulatory Commission (FERC) mandated operational changes to the electricity transmission grid, impact of the investment performance of the Company's pension plan, changes in the economy, weather conditions, realization of recognized but unrealized market valuation gains on forward energy contracts, market valuation of forward energy contracts, availability of resin supliers, resin prices, governmental and regulatory action, fuel and purchased power costs and environmental issues. Anticipated higher operating costs and carrying charges on increased capital investment in plant, if not offset by proportionate increases in operating revenues and other income (either by appropriate rate increases, increases in unit sales, or increases in nonelectric operations), will affect future earnings.

Electric Operations

Growth of Electric Revenue

Growth in electric sales will be subject to a number of factors, including the volume of sales of electricity to other utilities, the effectiveness of demand-side management programs, weather, competition, the price of alternative fuels, the rate of economic growth or decline in the electric utility's service area and potential acquisitions of other systems. The electric utility's business depends primarily on the use of electricity by customers in its service area and the demands of its wholesale customers. Electric kwh sales to retail customers increased 0.7% in 2003, 2.4% in 2002 and 2.9% in 2001.

Otter Tail Power Company has indicated interest in the South Dakota-based electric and gas operations of NorthWestern Corporation, which filed for bankruptcy in the fall of 2003 and is currently restructuring. Merrill Lynch has been retained as the financial advisor to negotiate with NorthWestern's unsecured creditors in the event of a sale of assets. Otter Tail Power Company co-owns two plants with NorthWestern and also has proximity to and a degree of overlap with NorthWestern service areas. Otter Tail Power Company's interest does not include NorthWestern's Montana properties or operations. The acquisition of the South Dakota assets would increase the number of utility customers by roughly 45%. Because the process has just begun, it is not possible to determine the liklihood of the acquisition being completed.

Factors beyond the electric utility's control, such as mergers and acquisitions, geographical location, transmission reservation costs, unplanned interruptions at the electric utility's generating plants, fluctuations in market prices of open forward energy contracts subject to mark-to-market accounting and the effects of deregulation, could lead to greater volatility in the volume and price of sales of electricity to other utilities. Activity in the short-term energy market is subject to change based on a number of factors and it is difficult to predict the quantity of wholesale power sales or prices for wholesale power, although it appears that market conditions for wholesale power transactions will not be as robust in the future because of generating unit additions in the power pool and the advent of transmission system operators mandated by the FERC.

Regulation

Electric utility operations remain regulated in all jurisdictions in which Otter Tail Power Company operates. Rates of return earned on utility operations are subject to review by the various state commissions that have jurisdiction over the electric rates charged by the Company. These reviews could result in future revenue and income reductions when actual rates of return are deemed by regulators to be in excess of allowed rates of return.

On December 29, 2000 the North Dakota Public Service Commission (NDPSC) approved a performance-based ratemaking plan that links allowed earnings in North Dakota to seven defined performance standards in the areas of price, electric service reliability, customer satisfaction and employee safety. The plan is in place for 2001 through 2005, unless suspended or terminated by the NDPSC or the Company. The electric utility's 2003 rate of return is expected to be within the allowable range defined in the plan.

Fuel Costs

The electric utility has an agreement for Big Stone Plant's coal supply through December 31, 2004. The Company is in negotiations with a new coal supplier for a long-term contract beginning in 2005. The electric utility has been unable to negotiate a competitive delivery rate for coal to the Big Stone Plant with rail carriers. Coal is being shipped to Big Stone Plant under a tariff rate. The electric utility has commenced a proceeding before the Surface Transportation Board requesting the Board set a competitive rate, with a decision expected early in 2005. The electric utility expects the outcome to have a favorable impact on its fuel costs for Big Stone Plant.

The MAPP region has experienced a very slight increase in availability of surplus generation capacity due to the addition of peaking capacity. However, energy availability has declined due to a regional drought that has significantly reduced hydro generation in Manitoba and on the Missouri River Basin. The region is also experiencing increasing transmission system congestion, impacting the wholesale power market. While the availability of the electric utility's plants has been excellent, the loss of a major plant could expose the electric utility to higher purchased power costs. Two factors mitigate this financial risk. First, wholesale sales contracts include provisions to release the electric utility from its obligations in the event of a plant outage; and second, the electric utility has COE adjustment clauses that allow pass through of most of the increased energy costs to retail customers. However, increases in fuel costs or regional generating capacity could have a negative impact on wholesale electric sales and profit margins.

Environmental

Current regulations under the Federal Clean Air Act (the Act) are not expected to have a significant impact on future capital requirements or operating costs. However, proposed or future regulations under the Act, changes in the future coal supply market, and/or other laws and regulations could impact such requirements or costs. The electric utility anticipates that, under current regulatory principles, any such costs could be recovered through rates. All of the electric utility's electric generating plants operated within the Act's phase two standards for sulfur-dioxide and nitrogen-oxide emissions in 2003. Ongoing compliance with the phase two requirements is not expected to significantly impact operations at any of the electric utility's plants.

The Act called for Environmental Protection Agency (EPA) studies of the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and sent reports to Congress. The Act required that the EPA make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced that it would regulate mercury emissions from electric generating units. The EPA Administrator signed the proposed mercury rule on December 15, 2003. The proposal included two options for regulating mercury emission from coal-fired electric generating units. One option would set technology-based maximum achievable control technology standards under paragraph 112(d) of the Act. The other option embodies a market-based cap and trade approach to emissions reduction. The electric utility is currently evaluating the proposal. Because promulgation of rules by the EPA has not been completed, it is not possible to assess to what extent this regulation will impact the electric utility.

The EPA has targeted electric steam generating units as part of an enforcement initiative relative to compliance with the Act. The EPA is attempting to determine if utilities violated certain provisions of the Act by making major modifications to their facilities without installing state-of-the-art pollution controls. On January 2, 2001 the electric utility received a request from the EPA pursuant to Section 114(a) of the Act requiring the electric utility to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. The electric utility has responded to that request. In March 2003, the EPA conducted a review of the plant's outage records as a follow-up to their January 2001 data request. Copies of the designated documents were provided to the EPA on March 21, 2003. At this time, the electric utility cannot determine what, if any, actions will be taken by the EPA.

At the request of the Minnesota Pollution Control Agency (MPCA), the electric utility has an ongoing investigation at the Hoot Lake Plant closed ash disposal sites. The MPCA continues to monitor site activities under their Voluntary Investigation and Cleanup Program. In April 2001, the electric utility submitted a Remedial Investigation Work Plan to the MPCA describing its plans to further investigate the environmental impact of the closed portion of the Hoot Lake Plant ash disposal site. The MPCA approved the plan, with some suggested modifications and these tasks have been completed. The MPCA also asked that the electric utility eliminate a ground water seepage that was originating from one of the disposal areas. Site work was completed in early November 2001; however, seepage reappeared in a new location in the spring of 2002. The electric utility initiated additional studies to further characterize the site and its report was submitted to the MPCA in March 2003 for their review and comment. The MPCA approved portions of the remediation measures that the electric utility proposed and those were implemented in 2003. Although the electric utility is still evaluating various options, its preliminary estimate of remediation costs to address the ash disposal site issues over the next three years is not expected to have a material impact on the Company's consolidated net income, financial position or cash flows.

Deregulation and Legislation

In the aftermath of the August 14, 2003 blackout, the FERC is contemplating how to enforce reliability standards, with or without energy legislation giving them explicit authority to do so. On the electricity market front, FERC's 2002 Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD) met significant political resistance, especially from the Southeast and Western regions of the United States. As a direct result, FERC published a Wholesale Market Platform (WMP) white paper that provides for regional flexibility and state regulator involvement through Regional State Committees (RSCs).

The state regulators in the Midwest Independent Transmission System Operator (MISO) region initiated the startup of an RSC called the Organization of MISO States (OMS). The OMS has no regulatory authority. The purpose of the OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, the FERC, other relevant government entities and state commissions as appropriate.

MISO has delayed startup of its electricity markets until December 1, 2004. The integration of the electric utility's electric facilities with its region's nonjurisdictional utilities presents a challenge for a MISO market startup. MISO plans to implement a Locational Marginal Pricing (LMP) market on December 1, 2004. The Company is making preparations in advance of market implementation. Those preparations include participation in MISO working groups and committees, evaluation of software to assist in market operations, purchase of LMP forecasting software, and staff additions to meet the needs of a new market. LMP intends to manage transmission congestion more effectively than current processes, improve reliability of the grid, increase market efficiency, and provide greater price transparency to regulators. However, a recent Department of Energy study shows that wholesale market prices in the MAPP region will increase 10% from 2005-2010, remain unchanged from 2011-2015, and fall by 1% from 2016-2020. The study raises doubts about benefits of LMP in the MAPP region. Increased market efficiency and price transparency may reduce wholesale electric sales margins from current levels.

Electric retail deregulation was not a subject debated in any of the state legislatures in the electric utility's service territory (Minnesota, North Dakota, and South Dakota) in 2003. Further, none of these state legislatures passed significant new requirements negatively affecting the ownership or operation of investor-owned utility assets in 2003.

Nonelectric Operations

In 2003, approximately 14% of the Company's net income was contributed by nonelectric operations. The Company plans to make additional acquisitions. The following guidelines are used when considering acquisitions: emerging or middle market company; proven entrepreneurial management team that will remain after the acquisition; products and services intended for commercial rather than retail consumer use; the ability to provide immediate earnings and future growth potential. The Company intends to grow earnings as a long-term owner of its operating companies. The Company also assesses the performance of its operating companies' return on capital and will consider divesting under-performing operating companies. Continuing growth from nonelectric operations could result in earnings, cash flow and stock price volatility.

While the Company cannot predict the success of its current nonelectric businesses, the Company believes opportunities exist for growth in these business segments. Factors that could affect the results of its nonelectric businesses include, but are not limited to, the following: fluctuations in the cost and availability of raw materials and the ability to maintain favorable supplier arrangements and relationships; competitive products and pricing pressures and the ability to gain or maintain market share in trade areas; general economic conditions; interest rates and their impact on housing starts; the impact of government regulation; effectiveness of advertising, marketing, and promotional programs; impairment of goodwill recorded in connection with the acquisition of nonelectric businesses; adverse weather conditions; and competition in the transportation industry. The failure of Congress to pass a broad energy bill in 2004 could have an unfavorable impact on the Company's operations that manufacture towers for the wind energy industry.

Critical Accounting Policies Involving Significant Estimates

The Company's 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 the Company's consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. 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.

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, environmental liabilities, valuation of forward energy contracts, unbilled electric revenues, unscheduled power exchanges, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs. 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 Company's more significant judgments and estimates used in the preparation of the consolidated financial statements.

Pension and Other Postretirement Benefits Obligations and Costs

Pension and postretirement benefit liabilities and expenses for the Company's 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 the Company's pension and postretirement benefit plans and related assumptions is included in note 10 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 the Company's 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 the Company's benefit expenses in the year of the change. Also, a reduction in the expected rate of return on pension plan assets in the Company's 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.

For the Company's pension fund, the average rate of return on assets over the past five years of 7.6% compared to an average assumed rate of 9.3% combined with a reduction in the discount rate from 7.5% at year-end 2001 to 6.25% at year-end 2003 contributed to a shift from a $14 million unrecognized actuarial gain as of December 31, 2001 to a $23 million unrecognized actuarial loss as of December 31, 2003. A 22.9% return on plan assets in 2003 was a major factor contributing to a shift from $5.4 million net pension liability and an accumulated other comprehensive loss of $7 million as of December 31, 2002 to a prepaid pension asset of $8 million and elimination of the $7 million accumulated other comprehensive loss as of December 31, 2003. Pension benefit costs for 2004 are expected to be $2.1 million compared to $1.5 million in 2003. The impact on 2004 pension benefit costs of the change in the estimated discount rate from 6.75% at year-end 2002 to 6.25% at year-end 2003 will be more than offset by the reduction in the assumed rate of increase in future compensation levels from 4.25% at year-end 2002 to 3.75% at year-end 2003.

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 2003, all other factors being held constant: a 0.25 increase (or decrease) in the discount rate would have decreased (or increased) the 2003 pension benefit cost by $277,000; a 0.25 increase (or decrease) in the assumed rate of increase in future compensation levels would have increased (or decreased) the 2003 pension benefit cost by $355,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) the 2003 pension benefit cost by $380,000.

In 2003, the Company's Executive Survivor and Supplemental Retirement Plan (ES&SRP) accrued benefit liability increased by $1.9 million as a result of an increase in accumulated benefits earned and a reduction in the discount rate from 6.75% at year-end 2002 to 6.25% at year-end 2003. Shareholders' equity increased by $0.6 million in the form of a reduction to "other comprehensive loss" due to plan amendments that resulted in an increase in unrecognized prior service costs. The 0.50 decrease in the assumed discount rate and the 0.25 increase in the assumed rate of increase in future compensation levels as of December 31, 2003 will contribute to increases in the Company's ES&SRP periodic benefit costs which are currently projected to be $3.1 million in 2004, $3.2 million in 2005, $3.4 million in 2006, $3.5 million in 2007 and $3.7 million in 2008.

A decrease in the discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 contributed to a $2.7 million increase in the postretirement medical benefit plan's projected benefit obligation and a $0.3 million increase in the plan's unrecognized actuarial loss from year-end 2002 to year-end 2003. The changes in these factors will be offset by updates to actuarial tables resulting in a minor increase in postretirement healthcare benefit costs from $4.78 million in 2003 to a projected $4.83 million in 2004. Subsequent increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change these projected costs. A 0.25 increase (or decrease) in the discount rate would have decreased (or increased) the 2003 postretirement medical benefit cost by $132,000. See note 10 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

Revenue Recognition

The construction companies and three 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 costs incurred to total estimated costs. The duration of the majority of these contracts is less than a year. Revenues recognized, including revenues recognized by Foley prior to acquisition, on jobs in progress as of December 31, 2003 were $138 million. There are no losses expected on jobs in progress at year-end 2003. The Company believes that 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

The electric utility’s forward contracts for the purchase and sale of energy are considered derivatives subject to mark-to-market accounting under generally accepted accounting principles. The market prices used to value the electric utility’s forward contracts for the purchases and sales of electricity are determined by survey of counterparties by the electric utility’s power services personnel responsible for contract pricing and, as such, are estimates. Over 69% of the forward purchase and sales contracts that are marked to market as of December 31, 2003 are offsetting in terms of volumes and delivery periods. Over 93% of these forward energy transactions by volume are scheduled for settlement prior to May 1, 2004.

Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can result in transmission constraints and the cancellation of scheduled transactions by the independent transmission system operator. In these situations, which are relatively infrequent in occurrence, the counterparties to the cancelled transaction are generally not made whole for the difference in the contract price and the market price of the electricity at the time of cancellation. In some instances the electric utility may deliver on a sale where its offsetting purchase has been cancelled or take delivery on a purchase where its offsetting sale has been cancelled. All forward energy transactions are subject to a small, and likely unquantifiable, risk of cancellation by the independent transmission system operator due to unanticipated physical constraints on the transmission system. At the time of cancellation, the electric utility could be in a gain or loss position depending on the market price of electricity relative to the contract price and the electric utility’s position in the transaction.

Allowance for Doubtful Accounts

The Company encounters risks associated with sales and the collection of the associated accounts receivable. As such, the Company records a monthly provision for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, the Company primarily utilizes a historical rate 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, the Company compares the identified credit risks with the allowance that has been established using historical experience and adjusts the allowance accordingly. In circumstances where the Company is aware of a specific customer’s inability to meet its financial obligations, the Company records a specific allowance for bad debts to reduce the net recognized receivable to the amount the Company reasonably believes will be collected.

The Company believes the accounting estimate 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 2003, $1.0 million of bad debt expense was recorded and the allowance for doubtful accounts was $2.5 million (2.3% of trade accounts receivable) as of December 31, 2003. 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 the Company's allowance for doubtful accounts based on outstanding receivables at December 31, 2003 would result in a $1.1 million increase or decrease in bad debt expense.

Although an estimated allowance for doubtful accounts on the Company's 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 due largely 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 3.07% in 2003, 3.08% in 2002 and 3.06% in 2001. 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 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. The Company believes that the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries in which its companies operate or innovations in technology could result in a reduction of the estimated useful lives of the Company's property, plant and equipment or in an impairment write-down of the carrying value of these properties.

Asset Impairment

The Company is 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. The Company applies 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.

The Company believes that 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, 2003 an assessment of the carrying values of the Company's long-lived assets and other intangibles indicated that these assets were not impaired.

Goodwill Impairment

Beginning in 2002, 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.

The Company believes that 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 that the goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

As of December 31, 2003 an assessment of the carrying values of the Company's goodwill indicated no impairment.

Key Accounting Pronouncements

SFAS No. 143: The Financial Accounting Standards Board (FASB) has issued SFAS No. 143, Accounting for Asset Retirement Obligations (ARO), which provides accounting requirements for retirement obligations associated with tangible long-lived assets. The Company adopted SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal constructions under the doctrine of promissory estoppel. Adoption of SFAS No. 143 changed the accounting for ARO costs of the utility's generating plants. SFAS No. 143 requires the present value of the future decommissioning cost to be recognized as a liability on the balance sheet with an offsetting amount being added to the capitalized cost of the related long-lived asset. The liability will be accreted to its present value each month and the capitalized cost will be depreciated over the useful life of the related asset.

The Company's asset retirement obligations include site restoration, the closure of ash pits and the removal of storage tanks and asbestos at certain electric utility generating plants. The Company has legal obligations associated with retirement of other long-lived assets used in its electric operations that cannot be reasonably estimated because the useful lives of those assets are not determinable. There are no assets legally restricted for the settlement of any of the Company's asset retirement obligations. The Company reclassified $35.4 million in accumulated reserves related to estimated removal costs from accumulated depreciation and amortization to a regulatory liability on the face of its Consolidated Balance Sheet as of December 31, 2002. Disclosure requirements under SFAS No. 143 are included in note 1 to consolidated financial statements.

SFAS No. 149: The FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, in April 2003. The statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement is effective for contracts entered into or modified after June 30, 2003. With the issuance of SFAS No.149, any forward contracts for the purchase or sale of energy entered into after June 30, 2003 that do not meet the definition of a capacity contract and are subject to unplanned netting, referred to as a book out in the utility industry, are not eligible for the normal purchases and sales exception provided for under SFAS No. 133 and modified by SFAS No. 149. These contracts are considered derivatives and are now subject to mark-to-market accounting. This classification applies to virtually all of the electric utility's forward wholesale purchases and sales of energy, which, prior to the issuance of SFAS No. 149, qualified for the normal purchases and sales exception from mark-to-market accounting treatment on the basis that it was probable that these contracts would not settle net and would result in physical delivery. As a result of the issuance of SFAS No. 149, unrealized gains and losses on forward purchases and sales of energy are now recorded by the electric utility. All provisions of this statement have been applied prospectively.

The electric utility recorded $4.1 million in net marked-to-market gains on derivative energy contracts in 2003, which reflects the difference between the contracted prices for forward purchases and sales of energy and the fair market values of contracts with matching terms and characteristics from the time the contracts are entered into until they are settled. As of December 31, 2003, $2.1 million in recognized marked-to-market net gains was unrealized. The electric utility expects these gains to be realized within the first six months of 2004. A portion of the marked-to-market value of derivative assets and liabilities is not reflected in current income but has been deferred under regulatory accounting treatment until realized at the time of physical delivery.

EITF Issue 03-11: At the July 31, 2003 EITF meeting, EITF Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not "Held for Trading Purposes" as Defined in Issue No. 02-3, was discussed. The EITF reached a consensus by agreeing that determining whether realized gains and losses on derivative contracts not "held for trading purposes" should be reported on a net or gross basis is a matter of judgment that depends on the relevant facts and circumstances. The FASB ratified the EITF consensus at its August 13, 2003 meeting. The reporting requirements of EITF Issue 03-11 are applicable to financial statement presentation in the fourth quarter of 2003. The electric utility determined that the net method of reporting was appropriate for its forward energy contracts. Revenue from the electric utility's wholesale sales of energy purchased from other suppliers are now reflected net of the related purchase power costs in electric revenues on the Company's consolidated statements of income for the years 2003, 2002 and 2001. The effects of the application of EITF Issue 03-11 and reclassification of prior year's reported revenues are shown in the table under Revenue Recognition in note 1 to consolidated financial statements. The application of the reporting requirements of EITF Issue 03-11 had no effect on the Company's consolidated net income, financial position or cash flows.

FASB Interpretation (FIN) No. 46 (revised December 2003), Consolidation of Variable Interest Entities, is an interpretation of Accounting Research Bulletin No. 51, that addresses consolidation by business enterprises of variable interest entities which have certain characteristics related to equity at risk and rights and obligations to profits and losses. The effective date for application of certain provisions of FIN 46 has been deferred until the first quarter of 2004 for interests in variable interest entities created before February 1, 2003 and held by a public entity that has not previously applied the provisions of FIN 46. Implementation of FIN 46 will have no impact on the Company's consolidated net income, financial position or cash flows.

SFAS No. 132 (revised 2003), Employers' Disclosures about Pensions and Other Postretirement Benefits, was revised in 2003 to require additional footnote disclosures about the assets, obligations, cash flows and net periodic benefit cost to defined benefit pension plans and other defined benefit postretirement plans. The additional disclosures include information describing the types of plan assets, investment strategy, measurement dates, plan obligations, cash flows, and components of net periodic benefit cost recognized during interim periods. This statement is effective for financial statements with fiscal years ending after December 15, 2003. See note 10 to consolidated financial statements.

Quantitative and Qualitative Disclosures About Market Risk

At December 31, 2003 the Company had limited exposure to market risk associated with interest rates and commodity prices and no exposure to market risk associated with changes in foreign currency exchange rates.

The majority of the Company's 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. The Company manages its 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, 2003 the Company had $30.6 million of long-term debt subject to variable interest rates. Assuming no change in the Company's financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2003 interest expense and pretax earnings would change by approximately $306,000.

The Company has not used interest rate swaps to manage net exposure to interest rate changes related to the Company's portfolio of borrowings. The Company maintains a ratio of fixed-rate debt to total debt within a certain range. It is the Company's policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet its stated objectives. The Company does not enter into transactions for speculative or trading purposes.

The electric utility's retail portion of fuel and purchased power costs are subject to cost-of-energy adjustment clauses that mitigate the commodity price risk by allowing a pass through of most of the increase or decrease in energy costs to retail customers. In addition, the electric utility participates in an active wholesale power market providing access to energy resources that may serve to mitigate price risk.

The Company's energy services subsidiary markets natural gas to approximately 150 retail customers. Some of these customers are served under fixed-price contracts. There is price risk associated with these limited number of fixed-price contracts since the corresponding cost of natural gas is not immediately locked in. This price risk is not considered material to the Company. These contracts call for the physical delivery of natural gas and are considered executory contracts for accounting purposes. Current accounting guidance requires losses on firmly committed executory contracts to be recognized when realized.

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 energy. As of December 31, 2003 the electric utility had recognized, on a pretax basis, $2.1 million in net unrealized gains on open forward contracts for the purchase and sale of energy. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can result in transmission constraints and the cancellation of scheduled transactions by the independent transmission system operator. In these situations, the counterparties to the cancelled transaction are generally not made whole for the difference in the contract price and the market price of the electricity at the time of cancellation. In some instances the electric utility may deliver on a sale where its offsetting purchase has been cancelled or is undeliverable, or take delivery on a purchase where its offsetting sale has been cancelled or is undeliverable. All forward energy transactions are subject to a small, and likely unquantifiable, risk of cancellation by the independent transmission system operator due to unanticipated physical constraints on the transmission system. At the time of cancellation, the electric utility could be in a gain or loss position depending on the market price of electricity relative to the contract price and the electric utility's position in the transaction.

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 by the electric utility's power services' personnel responsible for contract pricing with adjustment for transmission costs required to move energy from its purchase point to its delivery point. Over 69% of the forward purchase and sales contracts that are marked to market as of December 31, 2003 are offsetting in terms of volumes and delivery periods.

The Company has 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. These policies require that most forward sales of electricity in wholesale markets be covered by offsetting forward purchases of electricity with matching terms and delivery dates or by the portion of company-owned generation projected to be in excess of retail load requirements. Currently, a portion of marked-to-market gains or losses on a sales contract will be offset by a marked-to-market loss or gain on the offsetting purchase contract.

The Company's energy risk management policy allows for long open positions with limitations on the aggregate marked-to-market value of open positions. These positions are closely monitored and covered with offsetting sales when the risk of loss exceeds predefined limits. The exposure to price risk of these open positions as of December 31, 2003 was not material.

The following table shows the effect of marking-to-market forward contracts for the purchase and sale of energy on the Company's Consolidated Balance Sheet as of December 31, 2003 and the change in its Consolidated Balance Sheet position from December 31, 2002 to December 31, 2003:

(in thousands)	December 31, 2003
Current asset – marked-to-market gain	$ 5,443
Regulatory asset – deferred marked-to-market loss	1,802
Total assets	7,245
Current liability – marked-to-market loss	(3,504)
Regulatory liability – deferred marked-to-market gain	(1,684)
Total liabilities	(5,188)
Net fair value of marked-to-market energy contracts	$ 2,057

(in thousands)	Year Ended December 31, 2003
Fair value at beginning of year	$ —
Amount realized on contracts delivered in 2003	(2,001)
Changes in fair value	4,058
Net fair value at end of period	2,057
Net change recorded as marked-to-market	$ 2,057

The $2.1 million in recognized but unrealized net gains on the forward energy purchases and sales marked-to-market on December 31, 2003 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2004	2nd Quarter 2004	4th Quarter 2004	Total
Net gain	$2,026	$11	$20	$2,057

The electric utility has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy purchases and sales agreements. The Company has 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. The Company's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2003 was $9.3 million. As of December 31, 2003 the Company had a net credit risk exposure of $1.6 million from 32 counterparties with investment grade credit ratings.

The $1.6 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 energy scheduled for delivery after December 31, 2003. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

Cautionary Statements

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, the Company makes the following statements.

The information in this annual report includes forward-looking statements. Important risks and uncertainties that could cause actual results to differ materially from those discussed in such forward-looking statements are set forth above under “Critical Accounting Policies Involving Significant Estimates” and “Factors Affecting Future Earnings.” Other risks and uncertainties may be presented from time to time in the Company’s future Securities and Exchange Commission filings.

Independent Auditors' Report

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, 2003 and 2002, 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, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statement. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective in 2003 the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* and SFAS No. 149, *Amendment of Financial Accounting Standards Board Statement No. 133 on Derivative and Hedging Activities,* and in 2002 the Company changed its method of accounting for goodwill and other intangible assets.

DELOITTE & TOUCHE LLP

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 23, 2004

Otter Tail Corporation

Consolidated Statements of Income—For the Years Ended December 31

(in thousands, except per-share amounts)	2003	2002	2001
Operating revenues	**$753,239**	$646,337	$579,168
Operating expenses			
Production fuel	**51,163**	44,122	41,776
Purchased power	**36,002**	30,915	24,527
Electric operation and maintenance expenses	**86,984**	80,534	75,531
Cost of goods sold	**372,734**	286,253	249,789
Other nonelectric expenses	**79,636**	70,160	58,497
Depreciation and amortization	**45,962**	42,613	42,100
Property taxes	**9,598**	9,423	9,464
Total operating expenses	**682,079**	564,020	501,684
Operating income	**71,160**	82,317	77,484
Other income and deductions — net	**1,292**	1,717	2,193
Interest charges	**17,866**	17,845	15,991
Income before income taxes	**54,586**	66,189	63,686
Income taxes	**14,930**	20,061	20,083
Net income	**39,656**	46,128	43,603
Preferred dividend requirements	**735**	736	1,993
Earnings available for common shares	**$ 38,921**	$ 45,392	$ 41,610
Average number of common shares outstanding—basic	**25,673**	25,176	24,600
Average number of common shares outstanding—diluted	**25,826**	25,397	24,832
Basic earnings per share	**$ 1.52**	$ 1.80	$ 1.69
Diluted earnings per share	**$ 1.51**	$ 1.79	$ 1.68
Dividends per common share	**$ 1.08**	$ 1.06	$ 1.04

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Balance Sheets, December 31

(in thousands)	2003	2002
Assets		
Current assets		
Cash and cash equivalents	**$ 7,305**	$ 9,937
Accounts receivable:		
Trade (less allowance for doubtful accounts of $2,510,000 for 2003 and $3,833,000 for 2002)	**107,634**	81,670
Other	**7,830**	1,466
Inventories	**56,966**	44,154
Deferred income taxes	**3,532**	4,487
Accrued utility revenues	**14,866**	11,633
Costs and estimated earnings in excess of billings	**4,591**	5,529
Other	**10,385**	5,337
Total current assets	**213,109**	164,213
Investments and other assets	**35,987**	36,135
Goodwill—net	**72,556**	64,557
Other intangibles—net	**7,096**	5,592
Deferred debits		
Unamortized debt expense and reacquisition premiums	**8,081**	8,895
Regulatory assets	**14,669**	10,238
Other	**1,600**	1,220
Total deferred debits	**24,350**	20,353
Plant		
Electric plant in service	**875,364**	835,382
Nonelectric operations	**193,858**	178,656
Total	**1,069,222**	1,014,038
Less accumulated depreciation and amortization	**453,791**	432,383
Plant—net of accumulated depreciation and amortization	**615,431**	581,655
Construction work in progress	**17,894**	41,607
Net plant	**633,325**	623,262
Total	**$ 986,423**	$ 914,112

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Balance Sheets, December 31

(in thousands)	2003	2002
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 30,000**	$ 30,000
Current maturities of long-term debt	**9,718**	7,690
Accounts payable	**83,338**	52,430
Accrued salaries and wages	**14,677**	18,194
Accrued federal and state income taxes	**4,152**	—
Other accrued taxes	**10,491**	10,150
Other accrued liabilities	**10,003**	5,760
Total current liabilities	**162,379**	124,224
Pensions benefit liability	**16,919**	20,484
Other postretirement benefits liability	**23,230**	20,382
Other noncurrent liabilities	**11,102**	7,840
Commitments (note 8)		
Deferred credits		
Deferred income taxes	**101,596**	94,147
Deferred investment tax credit	**11,630**	12,782
Regulatory liabilities	**42,926**	44,509
Other	**2,061**	2,550
Total deferred credits	**158,213**	153,988
Capitalization (page 36)		
Long-term debt, net of current maturities	**265,193**	258,229
Cumulative preferred shares	**15,500**	15,500
Common shares, par value $5 per share—authorized, 50,000,000 shares; outstanding, 2003—25,723,814 shares; 2002—25,592,160 shares	**128,619**	127,961
Premium on common shares	**26,515**	24,135
Unearned compensation	**(3,313)**	(1,946)
Retained earnings	**186,495**	175,304
Accumulated other comprehensive loss	**(4,429)**	(11,989)
Total common equity	**333,887**	313,465
Total capitalization	**614,580**	587,194
Total	**$986,423**	$914,112

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Common Shareholders' Equity

	Common shares outstanding	Par value, common shares	Premium on common shares	Unearned compensation	Retained earnings	Accumulated other comprehensive income/(loss)	Total equity
	(in thousands, except common shares outstanding)						
Balance, December 31, 2000	**24,574,288**	**$122,871**	**$ 50**	**$ (226)**	**$140,796**	**$ (220)**	**$263,271**
Common stock issuances	79,202	396	1,187				1,583
Amortization of unearned compensation—stock awards				75			75
Comprehensive income:							
Net income					43,603		43,603
Minimum liability adjustment						(1,755)	(1,755)
Total comprehensive income							41,848
Tax benefit for exercise of stock options			302				302
Remove capital stock expense $6.35 preferred shares			246		(246)		—
Purchase stock for employee purchase plan			(259)		(168)		(427)
Cumulative preferred dividends					(2,088)		(2,088)
Common dividends					(25,256)		(25,256)
Balance, December 31, 2001	**24,653,490**	**123,267**	**1,526**	**(151)**	**156,641**	**(1,975)**	**279,308**
Common stock issuances	938,670	4,694	22,094	(2,674)			24,114
Amortization of unearned compensation—stock awards				879			879
Comprehensive income:							
Net income					46,128		46,128
Minimum liability adjustment						(10,014)	(10,014)
Total comprehensive income							36,114
Tax benefit for exercise of stock options			720				720
Purchase stock for employee purchase plan			(205)				(205)
Cumulative preferred dividends					(736)		(736)
Common dividends					(26,729)		(26,729)
Balance, December 31, 2002	**25,592,160**	**127,961**	**24,135**	**(1,946)**	**175,304**	**(11,989)**	**313,465**
Common stock issuances	140,621	703	2,793	(2,477)			1,019
Common stock retirements	(8,967)	(45)	(225)				(270)
Amortization of unearned compensation—stock awards				1,110			1,110
Comprehensive income:							
Net income					39,656		39,656
Minimum liability adjustment						7,560	7,560
Total comprehensive income							47,216
Tax benefit for exercise of stock options			111				111
Purchase stock for employee purchase plan			(299)				(299)
Cumulative preferred dividends					(735)		(735)
Common dividends					(27,730)		(27,730)
Balance, December 31, 2003	**25,723,814**	**$128,619**	**$26,515**	**$(3,313)**	**$186,495**	**$ (4,429)**	**$333,887**

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

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

(in thousands)	2003	2002	2001
Cash flows from operating activities			
Net income	**$ 39,656**	$ 46,128	$ 43,603
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**45,962**	42,613	42,100
Deferred investment tax credit—net	**(1,152)**	(1,153)	(1,177)
Deferred income taxes	**3,078**	2,669	(1,441)
Change in deferred debits and other assets	**(3,324)**	(5,178)	(8,434)
Change in noncurrent liabilities and deferred credits	**8,026**	1,049	2,484
Allowance for equity (other) funds used during construction	**(1,355)**	(1,742)	(963)
Unrealized (gains)/losses on derivatives net of regulatory deferral	**(2,057)**	—	—
Other—net	**1,629**	1,399	(81)
Cash provided by (used for) current assets and current liabilities:			
Change in receivables and inventories	**(35,451)**	(4,192)	4,880
Change in other current assets	**(2,499)**	(2,512)	(432)
Change in payables and other current liabilities	**19,260**	2,288	(581)
Change in interest and income taxes payable	**5,182**	(4,572)	(2,429)
Net cash provided by operating activities	**76,955**	76,797	77,529
Cash flows from investing activities			
Capital expenditures	**(50,734)**	(75,533)	(53,596)
Proceeds from disposal of noncurrent assets	**1,621**	2,462	3,298
Acquisitions—net of cash acquired	**(12,896)**	(6,591)	(8,948)
Decreases/(increases) in other investments	**1,601**	5	(1,884)
Net cash used in investing activities	**(60,408)**	(79,657)	(61,130)
Cash flows from financing activities			
Net borrowings under line of credit	**—**	25,507	—
Proceeds from employee stock plans	**1,072**	3,091	1,347
Proceeds from issuance of long-term debt	**18,690**	65,124	121,146
Payments for retirement of long-term debt	**(9,906)**	(62,161)	(81,549)
Payments for debt issuance expenses	**(98)**	(2,677)	(1,880)
Redemption of preferred stock	**—**	—	(18,000)
Dividends paid and other distributions	**(28,937)**	(27,465)	(27,344)
Net cash (used in) provided by financing activities	**(19,179)**	1,419	(6,280)
Net change in cash and cash equivalents	**(2,632)**	(1,441)	10,119
Cash and cash equivalents at beginning of year	**9,937**	11,378	1,259
Cash and cash equivalents at end of year	**$ 7,305**	$ 9,937	$ 11,378
Supplemental disclosures of cash flow information			
Cash paid during the year for:			
Interest (net of amount capitalized)	**$ 16,781**	$ 16,831	$ 16,313
Income taxes	**$ 8,437**	$ 22,835	$ 23,575

See accompanying notes to consolidated financial statements.

Otter Tail Corporation

Consolidated Statements of Capitalization, December 31

(in thousands)	2003	2002
Long-term debt		
Lombard US Equipment Finance note, variable, 2.59% at December 31, 2003, due October 2, 2006	**$ 16,300**	$ —
Senior debentures 6.375%, due December 1, 2007	**50,000**	50,000
Senior notes 6.63%, due December 1, 2011	**90,000**	90,000
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
Pollution control refunding revenue bonds, variable, 1.35% at December 31, 2003, due December 1, 2012	**10,400**	10,400
Grant County, South Dakota pollution control refunding revenue bonds 4.65%, due September 1, 2017	**5,185**	5,185
Mercer County, North Dakota pollution control refunding revenue bonds 4.85%, due September 1, 2022	**20,765**	20,790
Obligations of Varistar Corporation:		
8.15% five-year term note, due October 31, 2005	**1,957**	3,531
7.80% ten-year term note, due October 31, 2007	**3,960**	6,712
Variable 2.87% at December 31, 2003, due July 3, 2007	**2,789**	3,634
Various up to 12.67% at December 31, 2003	**8,839**	11,022
Total	**275,195**	266,274
Less:		
Current maturities	**9,718**	7,690
Unamortized debt discount	**284**	355
Total long-term debt	**265,193**	258,229
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	**333,887**	313,465
Total capitalization	**$614,580**	$587,194

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 and other business operations. The electric segment is regulated while the other segments are not regulated. 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 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 (AFC). AFC, a noncash item, is included in utility construction work in progress. The amount of AFC capitalized was $1,970,000 for 2003, $2,636,000 for 2002 and $1,342,000 for 2001. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 3.07% in 2003, 3.08% in 2002 and 3.06% in 2001. Gains or losses on 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 useful lives (3 to 40 years) of the related assets. Replacement and major improvements are capitalized; 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 financial statements include the Company's 53.9% (Big Stone Plant) and 35% (Coyote Station) ownership interests in the assets, liabilities, revenue and expenses of Big Stone Plant and Coyote Station. Amounts at December 31, 2003 and 2002 included in the consolidated balance sheet are as follows:

(in thousands)	Big Stone Plant	Coyote Station
December 31, 2003		
Electric plant in service	$116,240	$146,431
Accumulated depreciation	(68,387)	(72,946)
Net plant	$ 47,853	$ 73,485
December 31, 2002		
Electric plant in service	$113,731	$146,739
Accumulated depreciation	(67,993)	(74,610)
Net plant	$ 45,738	$ 72,129

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. Should the sum of the expected future net cash flows be 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. 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 sale 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, the Company recognizes gains and losses on changes in the fair market value of derivative instruments over the period held on a net basis, in revenue, in accordance with the requirements of SFAS No. 133 as amended by SFAS No. 149 and, when realized, on a net basis in a manner prescribed by Emerging Issues Task Force (EITF) Issue 03-11. Gains and losses on forward energy contracts subject to regulatory treatment are deferred and recognized on a net basis in revenue in the period realized.

For those operating businesses recognizing revenue when shipped, the operating businesses 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 cost-of-energy adjustment clause — 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 cost-of-energy adjustment clause.

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

As of July 1, 2003 the Company's unrealized gains and losses on forward energy contracts, not meeting 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. Prior to the issuance of SFAS No. 149 in 2003, these forward energy contracts qualified for the normal purchases and sales exception in SFAS No. 133 as amended by SFAS No. 138; revenues on forward energy sales were recognized on delivery and costs related to forward energy purchases were recognized as purchased power expenses when the energy was received. With the issuance of SFAS No. 149, the Company's forward energy contracts not meeting the definition of a capacity contract and subject to unplanned netting no longer qualify for the normal purchase and sales exception. 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.

In the fourth quarter of 2003, the FASB reached a consensus on EITF Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not "Held for Trading Purposes." The Company determined that the net basis prescribed in EITF Issue 03-11 is the appropriate treatment for reporting its realized gains and losses on forward energy contracts. Accordingly, the Company has reclassified prior period purchased power expenses related to forward energy contracts as components of electric operating revenue. The effects of the reclassification on prior period income statements are shown in the following table.

(in thousands)	2002	2001
Operating revenue previously reported	$710,116	$654,132
Less: Cost of forward energy purchases for resale	(63,779)	(74,964)
Operating revenue under net reporting method	$646,337	$579,168
Purchased power expense previously reported	$ 94,694	$ 99,491
Less: Cost of forward energy purchases for resale	(63,779)	(74,964)
Purchased power expense under net reporting method	$ 30,915	$ 24,527

Plastics operating revenues are recorded when the product is shipped.

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

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

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 costs incurred to total estimated costs. 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 summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2003	December 31, 2002
Costs incurred on uncompleted contracts	$ 124,839	$ 42,768
Less billings to date	(137,881)	(44,572)
Plus estimated earnings recognized	13,611	6,340
	$ 569	$ 4,536

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, 2003	December 31, 2002
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 4,591	$5,529
Billings in excess of costs and estimated earnings on uncompleted contracts	(4,022)	(993)
	$ 569	$4,536

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 $1,489,000 as of December 31, 2003 and $1,621,000 as of December 31, 2002. These costs are amortized over a three-year period and evaluated annually for impairment.

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.

Stock-Based Compensation — As described in note 6, the Company has elected to follow the accounting provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, for stock-based compensation and to furnish the pro forma disclosures required under SFAS No. 123, Accounting for Stock-Based Compensation.

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 2001 through 2003 would have decreased as presented in the table below. This may not be representative of the pro forma effects for future years if additional options are granted.

	2003	2002	2001
	(in thousands, except per share amounts)		
Net income			
As reported	$39,656	$46,128	$43,603
Total stock-based employee compensation expense determined under fair value-based method for all awards net of related tax effects	(984)	(1,038)	(833)
Pro forma	$38,672	$45,090	$42,770
Basic earnings per share			
As reported	$ 1.52	$ 1.80	$ 1.69
Pro forma	$ 1.48	$ 1.76	$ 1.66
Diluted earnings per share			
As reported	$ 1.51	$ 1.79	$ 1.68
Pro forma	$ 1.47	$ 1.75	$ 1.64

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, environmental liabilities, unbilled electric revenues, valuations of forward energy contracts, unscheduled power exchanges, service contract maintenance costs, percentage-of-completion and actuarially determined benefit costs. 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.

Reclassifications — Certain prior year amounts have been reclassified to conform to 2003 presentation. Such reclassifications had no impact on net income, shareholders' equity or cash flows provided from operations.

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

Investments — At December 31, 2003 and 2002 the Company had investments of $4,616,000 and $5,359,000, respectively, in limited partnerships that invest in tax-credit qualifying affordable housing projects. These investments provided the Company with tax credits of $1,412,000 in 2003 and $1,418,000 in both 2002 and 2001. The balance of investments at December 31, 2003 consists of $2,378,000 in additional investments accounted for under the equity method and $4,149,000 in other investments accounted for under the cost method, with $837,000 related to participation in economic development loan pools. The balance of investments at December 31, 2002 consists of $2,476,000 in additional investments accounted for under the equity method and $6,055,000 in other investments accounted for under the cost method, with $1,303,000 related to participation in economic development loan pools. See further discussion under note 11.

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, 2003	December 31, 2002
Finished goods	$20,349	$15,795
Work in process	6,234	1,438
Raw material, fuel and supplies	30,383	26,921
Total inventories	$56,966	$44,154

Short-Term Debt — There was $30,000,000 in short-term debt outstanding as of December 31, 2003 and 2002. The average interest rate paid on short-term debt was 1.7% in 2003 and 2.2% in 2002. The interest rate on short-term debt outstanding on December 31, 2003 was 1.5%.

Goodwill and Intangible Assets — The Company adopted SFAS No. 142, Goodwill and Other Intangible Assets, on January 1, 2002. SFAS No. 142 eliminates the requirement to amortize goodwill and indefinite-lived intangible assets, requiring instead that those assets be measured for impairment at least annually, and more often when events indicate that an impairment exists. Intangible assets with finite lives will continue to be 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.

In adopting SFAS No. 142, the Company has performed the transitional reassessment and impairment tests required as of January 1, 2002 and determined that goodwill was not impaired and therefore no write-off was necessary. If goodwill had not been amortized in 2001, net income would have been higher by $2.45 million that year. The following table presents the effects of not amortizing goodwill on reported net income and basic and diluted earnings per share.

(in thousands, except per share amounts)	2003	2002	2001
Net income:			
Reported net income	$39,656	$46,128	$43,603
Add back: goodwill amortization, net of tax	—	—	2,449
Adjusted net income	$39,656	$46,128	$46,052
Basic earnings per share:			
Reported basic earnings per share	$ 1.52	$ 1.80	$ 1.69
Add back: goodwill amortization, net of tax	—	—	0.10
Adjusted basic earnings per share	$ 1.52	$ 1.80	$ 1.79
Diluted earnings per share:			
Reported diluted earnings per share	$ 1.51	$ 1.79	$ 1.68
Add back: goodwill amortization, net of tax	—	—	0.09
Adjusted diluted earnings per share	$ 1.51	$ 1.79	$ 1.77

The changes in the carrying amount of goodwill by segment are as follows:

(in thousands)	Balance December 31, 2002	Adjustment to goodwill acquired in 2002	Goodwill acquired in 2003	Goodwill impairment in 2003	Balance December 31, 2003
Plastics	$19,302	$ —	$ —	$ —	$19,302
Manufacturing	8,609	(377)	—	—	8,232
Health services	22,409	—	1,924	—	24,333
Other business operations	14,237	—	6,702	(250)	20,689
Total	$64,557	$(377)	$8,626	$(250)	$72,556

The Company had recorded $250,000 in goodwill related to the acquisition of an energy management firm in 2002. Based on an offer to purchase this entity in the fourth quarter of 2003, the Company determined the goodwill related to this entity was impaired and, accordingly, recorded a $250,000 charge to operating income in the fourth quarter of 2003.

Intangible assets with finite lives are being amortized over average lives that vary from one to five years. The amortization expense for these intangible assets was $630,000 for 2003, $535,000 for 2002 and $414,000 for 2001. The estimated annual amortization expense for these intangible assets for the next five years is: $709,000 for 2004, $502,000 for 2005, $365,000 for 2006, $241,000 for 2007 and $189,000 for 2008.

Total other intangibles as of December 31 are as follows:

	Gross carrying amount	Accumulated amortization	Net carrying amount
2003 (in thousands)			
Amortized intangible assets:			
Covenants not to compete	$2,610	$1,483	$1,127
Other intangible assets including contracts	2,367	1,118	1,249
Total	$4,977	$2,601	$2,376
Nonamortized intangible assets:			
Brand/trade name	$4,720	$ —	$4,720
2002 (in thousands)			
Amortized intangible assets:			
Covenants not to compete	$1,920	$1,143	$ 777
Other intangible assets including contracts	2,079	884	1,195
Total	$3,999	$2,027	$1,972
Nonamortized intangible assets:			
Brand name	$3,620	$ —	$3,620

The Company periodically evaluates the recovery of intangible assets based on an analysis of undiscounted future cash flows. Evaluations of all intangible assets including goodwill completed in January 2004 indicated that none of the intangible assets reported on the Company's consolidated balance sheet as of December 31, 2003 is impaired.

Adoption of New Accounting Pronouncements — **SFAS No. 143:** The FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations (ARO), which provides accounting requirements for retirement obligations associated with tangible long-lived assets. The Company adopted SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal constructions under the doctrine of promissory estoppel. Adoption of SFAS No. 143 changed the accounting for ARO costs of the utility's generating plants. SFAS No. 143 requires the present value of the future decommissioning cost to be recognized as a liability on the balance sheet with an offsetting amount being added to the capitalized cost of the related long-lived asset. The liability will be accreted to its present value each month and the capitalized cost will be depreciated over the useful life of the related asset.

The Company's asset retirement obligations include site restoration, the closure of ash pits and the removal of storage tanks and asbestos at certain electric utility generating plants. The Company has legal obligations associated with retirement of other long-lived assets used in its electric operations that cannot be reasonably estimated because the useful lives of those assets are not determinable. There are no assets legally restricted for the settlement of any of the Company's asset retirement obligations. The Company reclassified $35.4 million in accumulated reserves related to estimated removal costs from accumulated depreciation and amortization to a regulatory liability on the face of its Consolidated Balance Sheet as of December 31, 2002.

The present value of the legal asset retirement obligations as of December 31, 2003 of $1,595,000 is included in Other noncurrent liabilities on the Company's December 31, 2003 Consolidated Balance Sheet. The $1,595,000 liability includes the original obligation of $377,000 plus accumulated accretion expense of $1,113,000 from the date the obligation arose through January 1, 2003, plus $105,000 of additional accumulated accretion expense for 2003. Since the recovery of these estimated removal costs, which include accretion, has been provided for through the recovery of depreciation expense included as a component of current electric retail rates, there is no cumulative effect on income to be recorded related to the adoption of this accounting principle. The difference between current accretion expense and depreciation expense based on approved rates will accumulate as a regulatory asset until the actual cost to settle the asset retirement obligation has been incurred. At that time, the associated regulatory asset will be transferred to the associated regulatory liability account as required by regulatory accounting rules. The effects of the transitional noncash transactions described above are not reflected in the Company's consolidated statement of cash flows for the year ended December 31, 2003.

The following table shows the amount of the asset retirement obligation liability that would have been included in Other noncurrent liabilities in prior periods had the requirements of SFAS No. 143 been in effect in those periods.

	As of December 31,	
(in thousands)	**2002**	**2001**
As reported	—	—
Pro forma	$1,490	$1,392

SFAS No. 149: The FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, in April 2003. The statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement is effective for contracts entered into or modified after June 30, 2003. With the issuance of SFAS No. 149, any forward contracts for the purchase or sale of energy entered into after June 30, 2003 that do not meet the definition of a capacity contract and are subject to unplanned netting, referred to as a book out in the utility industry, are not eligible for the normal purchases and sales exception provided for under SFAS No. 133 and modified by SFAS No. 149. These contracts are considered derivatives and are now subject to mark-to-market accounting. This classification applies to virtually all of the Company's forward wholesale purchases and sales of energy, which, prior to the issuance of SFAS No. 149, qualified for the normal purchases and sales exception from mark-to-market accounting treatment on the basis that it was probable that these contracts would not settle net and would result in physical delivery. As a result of the issuance of SFAS No. 149, unrealized gains and losses on forward purchases and sales of energy are now recorded by the Company. All provisions of this statement have been applied prospectively.

The Company recorded $4.1 million in net marked-to-market gains on derivative energy contracts in 2003, which reflects the difference between the contracted prices for forward purchases and sales of energy and the fair market values of contracts with matching terms and characteristics from the time the contracts are entered into until they are settled. As of December 31, 2003, $2.1 million in recognized marked-to-market net gains was unrealized. The Company expects 98% of these gains to be realized within the first six months of 2004. A portion of net unrealized marked-to-market gains is not reflected in current income but has been deferred under regulatory accounting treatment until realized at the time of physical delivery.

EITF Issue 03-11: At the July 31, 2003 EITF meeting, EITF Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not "Held for Trading Purposes" as Defined in Issue No. 02-3, was discussed. The EITF reached a consensus by agreeing that determining whether realized gains and losses on derivative contracts not "held for trading purposes" should be reported on a net or gross basis is a matter of judgment that depends on the relevant facts and circumstances. The FASB ratified the EITF consensus at its August 13, 2003 meeting. The reporting requirements of EITF Issue 03-11 are applicable to financial statement presentation in the fourth quarter of 2003. The Company determined that the net method of reporting was appropriate for its forward energy contracts. Revenue from the Company's wholesale sales of energy purchased from other suppliers is now reflected net of the related purchase power costs in electric revenues on the Company's Consolidated Statements of Income for the years 2003, 2002 and 2001. The effects of the application of EITF Issue 03-11 and reclassification of prior years' reported revenues are shown in the table under Revenue Recognition in note 1. The application of the reporting requirements of EITF Issue 03-11 had no effect on the Company's consolidated net income, financial position or cash flows.

FASB Interpretation (FIN) No. 46 (revised December 2003), Consolidation of Variable Interest Entities, is an interpretation of Accounting Research Bulletin No. 51, that addresses consolidation by business enterprises of variable interest entities which have certain characteristics related to equity at risk and rights and obligations to profits and losses. The effective date for application of certain provisions of FIN 46 has been deferred until the first quarter of 2004 for interests in variable interest entities created before February 1, 2003 and held by a public entity that has not previously applied the provisions of FIN 46. Implementation of FIN 46 will have no impact on the Company's consolidated net income, financial position, or cash flows.

SFAS No. 132 (revised 2003), Employers' Disclosures about Pensions and Other Postretirement Benefits, was revised in 2003 to require additional footnote disclosures about the assets, obligations, cash flows and net periodic benefit cost to defined benefit pension plans and other defined benefit postretirement plans. The additional disclosures include information describing the types of plan assets, investment strategy, measurement dates, plan obligations, cash flows and components of net periodic benefit cost recognized during interim periods. This statement is effective for financial statements with fiscal years ending after December 15, 2003. The additional disclosures required under SFAS No. 132 are included in note 10 to these financial statements.

2. Business Combinations, Dispositions and Segment Information

On November 1, 2003 the Company acquired the assets and operations of Foley Company (Foley) for $12.3 million in cash. Foley is a mechanical and prime contracting firm based in Kansas City, Missouri, that provides a range of specialty contracting including design-and-build services for new construction, retrofitting, process piping, equipment settings, and instrumentation and control systems. Major clients include water and wastewater treatment plants, hospital and pharmaceutical facilities, power generation plants, and other industrial and manufacturing projects across a multi-state service area. Foley Company had gross revenues of $44.8 million in 2002. This acquisition expands the Company's construction services to a broader geographic region. Foley is included in the other business operations segment.

In 2003, the Company also acquired Topline Medical, Inc. and North Star Medical Systems, Inc. The aggregate price paid for the companies in 2003, neither of which was individually material, was $1.9 million in cash. These acquisitions will allow the health services segment to increase sales opportunities with an expanded line of products.

Below is a condensed balance sheet disclosing the preliminary allocation of the purchase price assigned to each major asset and liability category for the companies acquired in 2003.

(in thousands)	Foley	Others
Assets		
Current assets	$ 9,847	$ 675
Plant	3,793	45
Goodwill	6,702	1,924
Other intangible assets	1,653	102
Total assets	$21,995	$2,746
Liabilities and equity		
Current liabilities	$ 8,618	$ 669
Long-term debt	—	136
Other long-term liabilities	1,095	—
Equity	12,282	1,941
Total liabilities and equity	$21,995	$2,746

The above allocations are subject to adjustment. Goodwill related to the Foley acquisition is not deductible for income tax purposes. The goodwill related to the other acquisitions is deductible for income tax purposes over 15 years. Other intangible assets related to the Foley acquisition includes a $1,100,000 nonamortizable trade name and $553,000 in intangible assets being amortized over 5 years. Other intangible assets related to the other acquisitions are being amortized over 4 years.

On May 1, 2002 the Company acquired 100% of the outstanding stock of Computed Imaging Service, Inc. (CIS) of Houston, Texas for 158,257 shares of Otter Tail Corporation common stock and approximately $1.2 million in cash. CIS provides computed tomography and magnetic resonance imaging mobile services, interim rental, and sales and service of new, used and refurbished diagnostic imaging equipment. CIS serves hospitals and other healthcare facilities in the south-central United States. The acquisition of CIS allows the Company to expand its existing health services operations into another region of the country. CIS annual revenues were approximately $5.9 million in 2001.

On May 28, 2002 the Company acquired 100% of the outstanding stock of ShoreMaster, Inc. (ShoreMaster), of Fergus Falls, Minnesota for 303,124 shares of Otter Tail Corporation common stock and $2.3 million in cash. ShoreMaster is a leading manufacturer of waterfront equipment ranging from residential-use boatlifts and docks to commercial marina systems. The acquisition of ShoreMaster is expected to provide diversification and growth opportunities for the Company's manufacturing segment. ShoreMaster's annual revenues were approximately $20 million in 2001.

On October 1, 2002 the Company acquired 100% of the outstanding stock of Galva Foam Marine Industries, Inc. (Galva Foam), of Camdenton, Missouri for 256,940 shares of Otter Tail Corporation common stock and approximately $1.0 million in cash. Galva Foam is a leading manufacturer of waterfront equipment ranging from residential boatlifts and docks to commercial marina systems. The acquisition of Galva Foam in combination with the May 2002 acquisition of ShoreMaster expands the market reach of the Company's waterfront manufacturing product line nationwide with both saltwater and freshwater products. Galva Foam had annual revenues of approximately $13 million in 2001.

In 2002, the Company also acquired two other businesses, neither of which was individually material, one in energy management services and the other in health services. The total purchase price for these businesses was approximately $2 million in cash.

Below is a condensed balance sheet disclosing the fair value assigned to each major asset and liability category for the companies acquired in 2002.

(in thousands)	CIS	ShoreMaster	Galva Foam	Others
Assets				
Current assets	$ 1,439	$ 9,510	$4,953	$ 131
Plant	3,975	4,599	1,713	298
Goodwill	5,847	4,292	2,650	1,616
Other intangible assets	30	4,461	41	60
Total assets	$11,291	$22,862	$9,357	$2,105
Liabilities and equity				
Current liabilities	$ 1,747	$ 9,642	$2,304	$ 32
Long-term debt	2,584	2,723	—	—
Other long-term liabilities	707	797	372	—
Equity	6,253	9,700	6,681	2,073
Total liabilities and equity	$11,291	$22,862	$9,357	$2,105

All of the 2003 and 2002 acquisitions were accounted for using the purchase method of accounting. The pro forma effect of these acquisitions on 2002 and 2001 revenues, net income or earnings per share was not significant.

On September 4, 2001 the Company acquired the assets and operations of Interim Solutions and Sales, Inc. and Midwest Medical Diagnostics, Inc. of Minneapolis, Minnesota. These companies operate as a division of DMS Imaging, Inc. and provide mobile diagnostic imaging services on an interim basis for computed tomography and magnetic resonance imaging, fee-per-exam options and sales of previously owned imaging equipment. Revenues for 2000 were approximately $3.1 million. The excess of the purchase price over the net assets acquired was $2.2 million.

On September 10, 2001 the Company acquired the assets and operations of Nuclear Imaging, Ltd., of Sioux Falls, South Dakota. Nuclear Imaging provides mobile nuclear medicine, positron emission tomography and bone densitometry services to more than 120 healthcare facilities in the Midwest. Nuclear Imaging is a subsidiary of DMS Imaging, Inc. Revenues for 2000 were approximately $6.9 million. The excess of the purchase price over the net assets acquired was $4.8 million.

On November 1, 2001 the Company acquired the assets and operations of Titan Steel Corporation of Salt Lake City, Utah. Titan is a fabricator of steel products engaged in custom operations. Titan is an operating division of St. George Steel Fabrication, Inc. Revenues for 2000 were approximately $9 million. The excess of the purchase price over the net assets acquired was immaterial.

The above acquisitions of Interim Solutions and Sales, Inc., Midwest Medical

Diagnostics, Inc., Nuclear Imaging, Ltd. and Titan Steel Corporation were accounted for using the purchase method of accounting under SFAS No. 141. Under the transition provision of SFAS No. 142, no goodwill was amortized for these acquisitions during 2001.

On February 28, 2001 the Company acquired all of the outstanding stock of T.O. Plastics, Inc. in exchange for 451,066 newly issued shares of the Company's common stock. T.O. Plastics, Inc. custom manufactures returnable pallets, material and handling trays and horticultural containers. It has three facilities in Minnesota and one facility in South Carolina.

On September 28, 2001 the Company acquired all of the outstanding stock of St. George Steel Fabrication, Inc. in exchange for 270,370 newly issued shares of the Company's common stock. St. George Steel is a fabricator of steel products engaged in custom and proprietary operations located in Utah.

The above two acquisitions were accounted for as pooling-of-interests. Since the St. George Steel acquisition was initiated prior to June 30, 2001, pooling-of-interest accounting was allowed under the transition provision of SFAS No. 141.

Segment Information — The accounting policies of the segments are described under note 1 – Summary of Significant Accounting Policies. The Company's business operations consist of five segments based on products and services. Electric includes the electric utility operating in Minnesota, North Dakota and South Dakota.

Plastics consists of businesses involved in the production of polyvinylchloride (PVC) and polyethylene (PE) pipe in the Upper Midwest and Southwest regions of the United States.

Manufacturing consists of businesses involved in the production of waterfront equipment, wind towers, frame-straightening equipment and accessories for the auto repair industry, custom plastic pallets, material and handling trays, horticultural containers, fabrication of steel products, contract machining, and metal parts stamping and fabrication located in the Upper Midwest, Missouri and Utah.

Health services include businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment, and related supplies and accessories. These businesses also provide service maintenance, mobile diagnostic imaging, mobile positron emission tomography and nuclear medicine imaging, portable x-ray imaging and rental of diagnostic medical imaging equipment to various medical institutions located in 42 states.

Other business operations consists of businesses in electrical and telephone construction contracting, specialty contracting including design and build services for new construction, transportation, telecommunications, entertainment, energy services, and natural gas marketing, as well as the portion of corporate administrative and general expenses that is not allocated to other segments. The electrical and telephone construction contracting companies and energy services and natural gas marketing business operate primarily in the central region of the Unites States. The telecommunications companies operate in central and northeast Minnesota and the transportation company operates in 48 states and 6 Canadian provinces.

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 for the business segments for 2003, 2002 and 2001 is presented in the following table.

	2003	2002	2001
		(in thousands)	
Operating revenue			
Electric	$267,494	$244,005	$232,720
Plastics	86,009	82,931	63,216
Manufacturing	177,805	142,390	123,436
Health services	100,912	93,420	79,129
Other business operations	123,475	84,627	80,667
Intersegment eliminations	(2,456)	(1,036)	—
Total	$753,239	$646,337	$579,168
Depreciation and amortization			
Electric	$ 26,008	$ 24,910	$ 24,272
Plastics	2,126	1,760	3,229
Manufacturing	7,708	6,525	5,139
Health services	5,137	4,410	3,517
Other business operations	4,983	5,008	5,943
Total	$ 45,962	$ 42,613	$ 42,100
Operating income			
Electric	$ 57,537	$ 53,879	$ 57,150
Plastics	4,013	10,841	(1,391)
Manufacturing	8,133	9,477	12,175
Health services	5,248	8,654	6,862
Other business operations	(3,771)	(534)	2,688
Total operating income	$ 71,160	$ 82,317	$ 77,484
Other income and deductions – net	1,292	1,717	2,193
Interest charges	17,866	17,845	15,991
Income before income taxes	$ 54,586	$ 66,189	$ 63,686
Earnings available for common shares			
Electric	$ 33,411	$ 31,244	$ 31,065
Plastics	2,019	5,668	(1,628)
Manufacturing	3,885	4,524	6,117
Health services	2,464	4,555	4,213
Other business operations	(2,858)	(599)	1,843
Total	$ 38,921	$ 45,392	$ 41,610
Capital expenditures			
Electric	$ 28,177	$ 45,842	$ 34,992
Plastics	3,984	5,592	1,572
Manufacturing	9,903	15,049	10,516
Health services	5,427	3,874	3,282
Other business operations	3,243	5,176	3,234
Total	$ 50,734	$ 75,533	$ 53,596
Identifiable assets			
Electric	$609,190	$586,231	$559,185
Plastics	58,538	54,926	45,649
Manufacturing	138,493	114,120	67,033
Health services	67,587	64,785	50,560
Other business operations	112,615	94,050	95,351
Total	$986,423	$914,112	$817,778

No single external customer accounts for 10% or more of the Company’s revenues. Substantially all sales and long-lived assets of the Company are within the United States.

3. Rate Matters

In 2001, the Minnesota Legislature exempted certain generation machinery and attached equipment from state personal property tax. The law also requires that any property tax savings resulting from this exemption be refunded to utility customers. As a result of this law, $272,600 in 2001 property tax savings was refunded to Minnesota retail electric customers in 2002. On January 1, 2003 a Property Tax Reduction Rider became effective which reduces base electric rates by 0.27% to reflect ongoing tax savings.

On December 29, 2000 the North Dakota Public Service Commission (NDPSC) approved a performance-based ratemaking plan that links allowed earnings in North Dakota to seven defined performance standards in the areas of price, electric service reliability, customer satisfaction and employee safety. The plan is in place for 2001 through 2005, unless suspended or terminated by the NDPSC or the Company. This plan provides the opportunity for the electric utility to raise its allowed rate of return and shares income with customers when earnings exceed the allowed return. During 2001, the electric utility achieved a rate of return on equity that exceeded targets under the plan which resulted in a sharing of the income between shareholders and customers and led to a $662,300 refund to North Dakota retail electric customers in 2002. Because the electric utility’s 2002 rate of return was within the allowable range defined in the plan, no sharing occurred in 2003. The electric utility’s 2003 rate of return is expected to be within the allowable range defined in the plan.

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, 2003**	**December 31, 2002**
Regulatory assets:		
Deferred income taxes	$12,750	$10,238
Debt expenses and reacquisition premiums	3,863	4,323
Deferred conservation program costs	882	844
Plant acquisition costs	285	329
Deferred marked-to-market losses	1,802	—
Accrued cost-of-energy revenue	3,693	768
Accumulated ARO accretion/depreciation adjustment	117	—
Total regulatory assets	$23,392	$16,502
Regulatory liabilities:		
Accumulated reserve for estimated removal costs	$33,579	$35,376
Deferred income taxes	7,496	8,960
Deferred marked-to-market gains	1,684	—
Gain on sale of division office building	167	173
Total regulatory liabilities	$42,926	$44,509
Net regulatory liability position	$19,534	$28,007

The regulatory assets and liabilities related to deferred income taxes are the result of the adoption of SFAS No. 109, Accounting for Income Taxes. Debt expenses and reacquisition premiums are being recovered from customers over the remaining original lives of the reacquired debt issues, the longest of which is 19 years. Deferred conservation program costs included in Deferred debits – Other represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant acquisition costs included in Deferred debits – Other will be amortized over the next 7 years. Accrued cost-of-energy revenue included in Accrued utility revenues will be recovered over the next nine months. All deferred marked-to-market gains and losses are related to forward purchases and sales of energy scheduled for delivery in 2004. The accumulated reserve for estimated removal costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from 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

With the issuance of SFAS No. 149, 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 upon entering into these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. Although these contracts are classified as derivatives, the electric utility does not use them for hedging and does not presently hold these contracts for trading purposes.

In 2003, the electric utility recorded wholesale sales of electricity totaling 3,782,899 mwhs. Of this total, 597,870 mwhs (15.8%) came from company-owned generation and 3,185,029 mwhs (84.2%) came from wholesale purchases. Net settlements, or book outs, constituted 9.5% of 2003 mwh sales by volume. Electric revenues for 2003 include $29,530,000 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts broken down as follows:

	(in thousands)	
Wholesale sales from company–owned generation		$18,428
Wholesale sales of purchased power at contract and market	$ 121,303	
Contract and market cost of purchased power resold	(114,259)	
Net margins on wholesale sales of purchased power		7,044
Marked-to-market gains on settled contracts	2,978	
Marked-to-market losses on settled contracts	(977)	
Net marked-to-market gain on settled contracts		2,001
Unrealized marked-to-market gains on open contracts	6,338	
Unrealized marked-to-market losses on open contracts	(4,281)	
Net unrealized marked-to-market gain on open contracts		2,057
Wholesale electric revenue		$29,530

A portion of gains and losses related to open forward energy contracts marked to market as derivative assets and derivative liabilities on the Company’s Consolidated Balance Sheet at December 31, 2003 are deferred under regulatory accounting treatment. There is a $5,443,000 derivative asset and $1,684,000 deferred derivative gain and regulatory liability, and a $3,504,000 derivative liability and $1,802,000 deferred derivative loss and regulatory asset related to open forward energy contracts on the Company’s Consolidated Balance Sheet at December 31, 2003. The derivative asset and derivative liability represent the difference between the contracted price and December 31, 2003 market price of forward energy contracts, of which over 93% are scheduled for settlement prior to May 1, 2004.

6. Common Shares and Earnings Per Share

New Issuances — Common stock issuances during 2003 included 47,552 shares issued as a result of stock options exercised, 2,169 shares issued as directors' compensation and 90,900 shares of restricted stock issued as officers' and directors' compensation. In order to maintain a balanced capital structure consistent with the risk profile of the Company's diversified mix of businesses, the Company began issuing new shares of common stock in January 2004 to meet the requirements of its employee stock purchase plan and dividend reinvestment program and share purchase plan rather than purchasing shares on the open market.

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 options, performance awards, restricted stock, stock appreciation rights and other types of stock grants or stock-based awards. The exercise price of the stock options is equal to the fair market value per share at the date of the grant. Options granted to outside directors are exercisable immediately and all other options and restricted stock granted as of December 31, 2003 vest ratably over a four-year period. The options expire ten years after the date of the grant. The Company accounts for the Incentive Plan under APB No. 25.

Presented below is a summary of the stock options activity:

Stock Option Activity

	2003		2002		2001	
	Options	Average exercise price	Options	Average exercise price	Options	Average exercise price
Outstanding, beginning of year	1,360,721	$24.68	1,265,042	$22.62	787,316	$19.55
Granted	222,750	27.24	278,750	31.34	582,000	26.33
Exercised	47,700	20.21	130,797	19.71	74,936	19.44
Forfeited	4,646	23.09	52,274	22.83	29,338	22.17
Outstanding, year-end	1,531,125	$25.16	1,360,721	24.68	1,265,042	22.62
Exercisable, year-end	791,661	$22.97	449,385	$21.75	257,369	$19.83
Fair value of options granted during year	$ 5.42		$ 7.07		$ 5.88	

The fair values of the options granted were estimated using the Black-Scholes option-pricing model under the following assumptions:

	2003	2002	2001
Risk-free interest rate	3.7%	5.2%	5.5%
Expected lives	7 years	7 years	7 years
Expected volatility	26.3%	26.0%	24.9%
Dividend yield	4.0%	4.0%	4.0%

The following table summarizes information about options outstanding as of December 31, 2003:

	Options outstanding			Options exercisable	
Range of exercise prices	Outstanding as of 12/31/03	Weighted-average remaining contractual life (yrs)	Weighted-average exercise price	Exercisable as of 12/31/03	Weighted-average exercise price
$18.80-$21.94	495,125	5.7	$19.48	437,250	$19.44
$21.95-$25.07	—	—	—	—	—
$25.08-$26.77	520,750	7.3	$26.25	276,750	$26.25
$26.78-$31.34	515,250	8.7	$29.53	77,661	$31.13

In addition to the stock options granted, 90,900, 85,800 and 1,681 shares of restricted stock were granted during 2003, 2002 and 2001, respectively. The total compensation cost recognized in income for stock-based employee compensation awards was $1,110,000 in 2003, $879,000 in 2002 and $125,000 in 2001. See note 1 for pro forma stock option information.

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 lower market price at either the beginning or the end of each six-month purchase period. Of the 400,000 common shares authorized for purchase under the Purchase Plan, 131,225 were still available for purchase as of January 1, 2004. To provide shares for the Purchase Plan, common shares were purchased in the open market totaling 66,724 shares in 2003, 57,997 shares in 2002 and 56,612 shares in 2001.

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 2002, common shares needed for the Plan were purchased in the open market.

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 10, 1997. One Right was also issued with respect to each common share issued after February 10, 1997. Each Right entitles the holder to purchase from the Company one one-hundredth of a share of newly created Series A Junior Participating Preferred Stock at a price of $70, subject to certain adjustment. The Rights are exercisable when, and are not transferable apart from the Company's common shares until, a person or group has acquired 15% or more, or commenced a tender or exchange offer for 15% or more, of the Company's common shares. If the specified percentage of the Company's common shares is acquired, each Right will entitle the holder (other than the acquiring person or group) to receive, on exercise, common shares of either the Company or the acquiring company having value equal to two times the exercise price of the Right. The Rights are redeemable by the Company's Board of Directors in certain circumstances and expire on January 27, 2007.

Earnings Per Share — Basic earnings per common share are calculated by dividing earnings available for common shares by the 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.

7. 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, 2003.

8. Commitments and Contingencies

At December 31, 2003 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $2,929,000. For capacity and energy requirements, the electric utility has agreements extending through 2008 at annual costs of approximately $16,708,000 in 2004, $15,307,000 in 2005, $14,755,000 in 2006, $14,771,000 in 2007 and $14,848,000 in 2008.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire between 2004 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $85,893,000 or to make payments in lieu thereof, under these contracts. The cost-of-energy adjustment mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

The amounts of future operating lease payments are as follows:

	Electric	Nonelectric	Total
		(in thousands)	
2004	$1,661	$19,033	$20,694
2005	1,661	16,144	17,805
2006	1,661	10,364	12,025
2007	1,661	5,815	7,476
2008	1,661	1,651	3,312
Later years	1,377	2,508	3,885
Total	$9,682	$55,515	$65,197

Rent expense was $25,684,000, $22,282,000 and $20,242,000, for 2003, 2002 and 2001, 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 probable liabilities on the eventual disposition of these matters. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all currently pending matters will not be material.

9. Short-Term and Long-Term Borrowings

Short-term debt — On August 25, 2003 the Company’s line of credit was increased from $50 million to $70 million. This line is available to support borrowings of the Company’s nonelectric operations. This line of credit bears interest at the rate of LIBOR plus 0.5% and expires on April 28, 2004. The Company does not anticipate any difficulties in renewing this line of credit. The Company’s 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. The Company’s obligations under this line of credit are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company’s nonelectric companies. As of December 31, 2003, $30 million of the $70 million line was in use.

The interest rate under the line of credit is subject to adjustment in the event of a change in ratings on the Company’s senior unsecured debt, up to LIBOR plus 0.8% if the ratings on the Company’s senior unsecured debt fall to BBB+ or below (Standard & Poor’s) or Baa1 or below (Moody’s). The line of credit also provides for accelerated repayment in the event the Company’s long-term senior unsecured debt is rated below BBB- (Standard & Poor’s) or Baa3 (Moody’s).

Long-Term Debt — 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, 2006, the stated maturity date of the note. The term of the note can be extended for additional one-year periods following the stated maturity date through October 1, 2010. The note bears interest at a variable rate of 3-month LIBOR plus 1.43% on the unpaid principal balance with interest payments due quarterly commencing on October 1, 2003 until the principal balance is repaid in full. The Company used proceeds from the note to pay down borrowings under the Company’s line of credit that were used to finance acquisitions and capital expenditures of its nonelectric subsidiaries. The covenants associated with the note are consistent with existing credit facilities. There are no rating triggers associated with this note.

In 2003, $25,000 of Mercer County, North Dakota pollution control refunding revenue bonds 4.85%, due September 1, 2022 were redeemed for estate settlement purposes and retired.

In 2002, the Company filed with the SEC a shelf registration statement for $200 million of unsecured debt securities. On September 27, 2002 the Company issued $65 million of senior unsecured notes under the shelf registration statement. The offering consisted of $40 million of 5.625% insured senior notes due 2017 and $25 million of 6.80% senior notes due 2032. Net proceeds from these issues were used to retire the Company's remaining first mortgage bonds and to repay short-term debt used to finance a portion of the costs related to the new gas-fired combustion turbine plant constructed by the electric utility.

The Company has the ability to issue up to an additional $135 million of unsecured debt securities from time to time under its shelf registration statement on file with the SEC. Proceeds from subsequent debt issuances under the shelf registration, if any, may be used for other general corporate purposes, including working capital, capital expenditures, debt repayment, the financing of possible acquisitions or stock repurchases.

The Company's 6.63% senior notes contain an investment grade put that could require the Company to prepay this series with a make-whole premium if the Company's senior unsecured debt is rated below Baa3 (Moody's) or BBB- (Standard & Poor's). The Company's obligations under the 6.63% senior notes are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company's nonelectric companies. The Company's Grant County and Mercer County pollution control refunding revenue bonds require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, 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). The Company believes the risk of the downgrade events described in this paragraph occurring is remote based on the current bond ratings of the Company combined with its strong debt-to-equity ratio and ability to generate cash from operations.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2003 for each of the next five years are $9,718,000 for 2004, $7,420,000 for 2005, $14,872,000 for 2006, $50,985,000 for 2007 and $445,000 for 2008.

Covenants — The Company's line of credit, its $90 million 6.63% senior notes due 2011 and Lombard US Equipment Finance note contain covenants that require the Company to maintain 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.

As of December 31, 2003 the Company was in compliance with all of the covenants under its line of credit and its other debt obligations.

10. Pension Plan and Other Postretirement Benefits

Pension Plan — The Company's noncontributory funded pension plan covers substantially all electric utility and corporate employees. 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.

The following tables provide a reconciliation of the changes in the plan's benefit obligations and fair value of assets over the two-year period ended December 31, 2003 and a statement of the funded status as of December 31 of both years:

	2003	2002
	(in thousands)	
Reconciliation of benefit obligation:		
Obligation at January 1	$145,262	$124,523
Service cost	3,779	3,120
Interest cost	9,491	9,269
Benefit payments	(8,190)	(7,760)
Plan amendments	—	2,770
Actuarial loss	3,817	13,340
Obligation at December 31	$154,159	$145,262
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	$113,803	$138,794
Actual return on plan assets	27,198	(17,231)
Benefit payments	(8,190)	(7,760)
Fair value of plan assets at December 31	$132,811	$113,803
Funded status	$ (21,348)	$ (31,459)
Unrecognized net actuarial loss	22,533	32,981
Unrecognized prior service cost	7,025	8,195
Net amount recognized	$ 8,210	$ 9,717

The following table provides the amounts recognized in the Consolidated Balance Sheets as of December 31:

	2003	2002
	(in thousands)	
Prepaid pension cost	$8,210	9,717
Additional minimum liability	—	(15,149)
Net pension asset/(liability)	$8,210	$ (5,432)
Intangible asset	—	8,195
Accumulated other comprehensive loss	—	6,954
Net amount recognized	$8,210	$ 9,717

Additional information on the status of the pension plan as of December 31:

	2003	2002
	(in thousands)	
Projected benefit obligation	$154,159	$145,262
Accumulated benefit obligation	130,072	119,235
Fair value of plan assets	132,811	113,803

Components of net periodic pension benefit cost:

	2003	2002	2001
		(in thousands)	
Service cost—benefit earned during the period	$ 3,779	$ 3,120	$ 2,544
Interest cost on projected benefit obligation	9,491	9,269	8,766
Expected return on assets	(12,933)	(14,957)	(14,610)
Amortization of transition asset	—	(73)	(235)
Amortization of prior-service cost	1,170	1,285	1,107

Amortization of net gain	—	(1,284)	(1,900)
Net periodic pension cost/(income)	$ 1,507	$ (2,640)	$ (4,328)

The change in the additional minimum liability included in other comprehensive loss was ($6,954,000) in 2003 and $6,954,000 in 2002.

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

	2003	2002
Discount rate	6.25%	6.75%
Rate of increase in future compensation level	3.75%	4.25%

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

	2003	2002
Discount rate	6.75%	7.50%
Long-term rate of return on plan assets	8.50%	9.50%
Rate of increase in future compensation level	4.25%	4.25%

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.

The assumed rate of return on pension fund assets for the determination of 2004 net periodic pension cost is 8.5%.

The Company's pension plan weighted-average asset allocations at December 31, 2003 and 2002, by asset category are as follows:

Asset Category	2003	2002
Enhanced core equity securities	53.3%	47.4%
Small capitalization equity securities	10.6%	8.7%
International equity securities	13.1%	10.6%
Total equity securities	77.0%	66.7%
Fixed-income securities	23.0%	33.3%
	100.0%	100.0%

The following objectives guide the decisions and investment strategy of the Company's pension committee for the 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.

The asset allocation strategy developed by the Company's pension 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 below 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 pension committee and/or investment managers, and required cash flows to and from the Plan. The tactical range shown below provides flexibility for the investment managers' portfolios to vary around the target allocation without the need for immediate rebalancing. The Company's pension committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining the targeted allocation percentages listed in the table below.

Security class	Strategic Target	Tactical Range
Enhanced core 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%

Cash Flows: The Company is not required to make a contribution to the pension plan in 2004, but is currently considering future funding options.

Executive Survivor and Supplemental Retirement Plan (ES&SRP) — The Company has an unfunded, nonqualified benefit plan for executive officers and certain key management employees. This plan provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their death 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.

The following tables provide a reconciliation of the changes in the plan's benefit obligations over the two-year period ended December 31, 2003 and a statement of the funded status as of December 31 of both years:

	2003	2002
	(in thousands)	
Reconciliation of benefit obligation:		
Obligation at January 1	$ 20,309	$ 14,365
Service cost	417	(51)
Interest cost	1,426	1,175
Plan amendments	1,083	(182)
Actuarial loss	2,242	5,566
Early retirement	—	240
Benefit payments	(1,026)	(804)
Obligation at December 31	$ 24,451	$ 20,309
Funded status:		
Funded status at December 31	$(24,451)	$(20,309)
Unrecognized prior-service cost	1,772	836
Unrecognized net actuarial loss	11,961	10,292
Net amount recognized	$(10,718)	$ (9,181)

The following table provides the amounts recognized in the Consolidated Balance Sheets as of December 31:

	2003	2002
	(in thousands)	
Accrued benefit liability	$(16,919)	$(15,052)
Intangible asset	1,772	836
Accumulated other comprehensive loss	4,429	5,035
Net amount recognized	$(10,718)	$ (9,181)

Additional information on the ES&SRP defined benefit pension plan as of December 31:

	2003	2002
	(in thousands)	
Projected benefit obligation	$24,451	$20,309
Accumulated benefit obligation	16,919	15,052
Fair value of plan assets	—	—

Components of net periodic pension benefit cost:

	2003	2002	2001
		(in thousands)	
Service cost—benefit earned during the period	$ 417	$ (51)	$ (76)
Interest cost on projected benefit obligation	1,426	1,175	956
Amortization of prior-service cost	147	86	191
Recognized net actuarial loss	573	398	117
Net periodic pension cost	$2,563	$1,608	$1,188
Early retirement benefit	—	240	—

Total	$2,563	$1,848	$1,188

The change in the additional minimum liability included in other comprehensive loss was ($606,000) in 2003 and $3,060,000 in 2002.

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

	2003	2002
Discount rate	6.25%	6.75%
Rate of increase in future compensation level	5.88%	5.63%

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

	2003	2002
Discount rate	6.75%	7.50%
Rate of increase in future compensation level	5.63%	4.50%

Cash Flows: The ES&SRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The Company expects to make contributions/benefit payments of $1,147,000 to plan participants in 2004.

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.

The following tables provide a reconciliation of the changes in the plan's benefit obligations over the two-year period ended December 31, 2003 and a statement of the funded status as of December 31 of both years:

	2003	2002
	(in thousands)	
Reconciliation of benefit obligation:		
Obligation at January 1	$ 39,318	$ 28,550
Service cost	1,009	615
Interest cost	2,619	2,166
Benefit payments	(2,981)	(2,436)
Participant premium payments	1,051	953
Plan amendments	—	(285)
Actuarial loss	992	9,755
Obligation at December 31	$ 42,008	$ 39,318
Funded status:		
Funded status at December 31	$(42,008)	$(39,318)
Unrecognized transition obligation	6,734	7,482
Unrecognized prior-service cost	700	395
Unrecognized loss	11,344	11,059
Net amount recognized	$(23,230)	$(20,382)

The net amounts recognized are shown on the Consolidated Balance Sheets as of December 31, 2003 and 2002 under the title of Other postretirement benefits liability.

Components of net periodic postretirement benefit cost:

	2003	2002	2001
		(in thousands)	
Service cost	$1,009	$ 615	$ 681
Interest cost	2,619	2,166	1,768
Amortization of transition obligation	748	748	748
Amortization of prior-service cost	(305)	(305)	111
Amortization of net loss/(gain)	708	—	(51)
Net periodic postretirement benefit cost	$4,779	$3,224	$3,257

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

	2003	2002
Discount rate	6.25%	6.75%

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

	2003	2002
Discount rate	6.75%	7.50%

Assumed healthcare cost-trend rates as of December 31:

	2003	2002
Healthcare cost-trend rate assumed for next year	11.0%	12.0%
Rate at which the cost-trend rate is assumed to decline	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2010	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 2003 would have the following effects:

	1 point increase	1 point decrease
	(in thousands)	
Effect on total of service and interest cost	$ 528	$ (611)
Effect on the postretirement benefit obligation	$5,153	$(4,263)

Cash Flows: The Company expects to contribute $2.4 million net of expected employee contributions for the payment of retiree medical benefits in 2004.

Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) — The Company's postretirement medical plan provides prescription drug coverage for Medicare-eligible retirees. The Company's accumulated postretirement benefit obligation (APBO) and net cost recognized for other postemployment benefits (OPEB) do not reflect the effects of the Act. The provisions of the Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to coordinate with the Medicare benefit. Specific authoritative guidance is pending from the FASB and Federal Government, and when that guidance is issued, it could require the Company to change its actuarially determined APBO and net cost for OPEB.

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 $1,030,000 for 2003 and $1,100,000 for both 2002 and 2001.

11. 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 $30.6 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

	December 31, 2003		December 31, 2002	
	(in thousands)			
	Carrying amount	Fair value	Carrying amount	Fair value
Cash and short-term investments	$ 7,305	$ 7,305	$ 9,937	$ 9,937
Other investments	11,143	11,143	13,890	13,890
Long-term debt	(265,193)	(292,604)	(258,229)	(277,261)

12. Property, Plant and Equipment

	2003	2002
	(December 31, in thousands)	
Electric plant:		
Production	$346,890	$314,093
Transmission	175,953	172,610
Distribution	272,909	268,400
General	79,612	80,279
Electric plant	875,364	835,382
Less accumulated depreciation and amortization	368,899	357,555
Electric plant net of accumulated depreciation	506,465	477,827
Construction work in progress	13,938	39,123
Net electric plant	$520,403	$516,950
Nonelectric operations plant	$193,858	$178,656
Less accumulated depreciation and amortization	84,892	74,828
Nonelectric plant net of accumulated depreciation	108,966	103,828
Construction work in progress	3,956	2,484
Net nonelectric operations plant	$112,922	$106,312
Net plant	$633,325	$623,262

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.

	Service Life Range	
(years)	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

13. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2003, 2002 and 2001) to net income before total income tax expense for the following reasons:

	2003	2002	2001
		(in thousands)	
Tax computed at federal statutory rate	$19,105	$23,167	$22,290
Increases (decreases) in tax from:			
State income taxes net of federal income tax benefit	2,011	2,441	2,564
Investment tax credit amortization	(1,152)	(1,152)	(1,176)
Differences reversing in excess of federal rates	(1,283)	(1,055)	(503)
Dividend received/paid deduction	(707)	(699)	(674)
Affordable housing tax credits	(1,412)	(1,418)	(1,418)
Permanent and other differences	(1,632)	(1,223)	(1,000)
Total income tax expense	$14,930	$20,061	$20,083
Overall effective federal and state income tax rate	27.4%	30.3%	31.5%
Income tax expense includes the following:			
Current federal income taxes	$11,665	$18,651	$21,110
Current state income taxes	3,141	3,856	3,107
Deferred federal income taxes	2,709	15	(2,247)
Deferred state income taxes	(21)	109	707
Affordable housing tax credits	(1,412)	(1,418)	(1,418)
Investment tax credit amortization	(1,152)	(1,152)	(1,176)
Total	$14,930	$20,061	$20,083

The Company's deferred tax assets and liabilities were composed of the following on December 31, 2003 and 2002:

	2003	2002
	(in thousands)	
Deferred tax assets		
Amortization of tax credits	$ 7,437	$ 8,345
Vacation accrual	1,926	1,836
Unearned revenue	1,592	1,420
Benefit liabilities	18,085	15,690
Cost of removal	13,096	13,797
Differences related to property	6,079	5,239
Transfer to regulatory liability	63	618
Other	2,068	2,956
Total deferred tax assets	$ 50,346	$ 49,901
Deferred tax liabilities		
Differences related to property	$(129,076)	$(123,021)
Excess tax over book pension	(3,260)	(3,855)
Transfer to regulatory asset	(12,751)	(10,237)
Other	(3,323)	(2,448)
Total deferred tax liabilities	$(148,410)	$(139,561)
Deferred income taxes	$ (98,064)	$ (89,660)

14. Quarterly Information (unaudited)

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	
	2003	2002	2003	2002	2003	2002	2003	2002
	(in thousands, except per share data)							
Operating revenues *(a)*	$172,149	$145,262	$180,057	$160,001	$200,895	$166,399	$200,138	$174,675
Operating income	18,302	18,935	14,920	19,848	22,302	22,979	15,636	20,555
Net income	9,862	10,032	8,434	10,587	11,961	12,882	9,399	12,627
Earnings available for common shares	9,678	9,848	8,250	10,403	11,777	12,698	9,216	12,443
Basic earnings per share	$ .38	$ .40	$ .32	$ .41	$ .46	$ .50	$ .36	$ .49
Diluted earnings per share	.38	.40	.32	.41	.46	.50	.36	.48
Dividends paid per common share	.27	.265	.27	.265	.27	.265	.27	.265
Price range:								
High	$ 28.59	$ 31.80	$ 28.90	$ 34.90	$ 28.41	$ 31.50	$ 28.50	$ 29.23
Low	23.76	25.75	25.27	28.50	25.60	22.82	25.92	25.22
Average number of common shares outstanding—basic	25,592	24,668	25,673	25,117	25,708	25,328	25,719	25,589
Average number of common shares outstanding—diluted	25,730	24,919	25,855	25,412	25,869	25,497	25,876	25,781

(a) Restated to reflect EITF Issue 03-11 reporting requirements.

Stock Listing

Otter Tail Corporation common stock trades on The Nasdaq Stock Market.

(Back To Top)

Section 3: EX-21.A (SUBSIDIARIES OF REGISTRANT)

Exhibit 21-A

OTTER TAIL CORPORATION

Subsidiaries of the Registrant
March 1, 2004

Company	State of Organization
Otter Tail Energy Services Company, Inc.	Minnesota
Overland Mechanical Services, Inc.	Minnesota
Otter Tail Assurance, LTD.	Cayman Islands
Varistar Corporation	Minnesota
Northern Pipe Products, Inc.	North Dakota
Vinyltech Corporation	Arizona
T.O. Plastics, Inc.	Minnesota
St. George Steel Fabrication, Inc.	Utah
DMI Industries, Inc.	North Dakota
BTD Manufacturing, Inc.	Minnesota
ShoreMaster, Inc.	Minnesota
Galva Foam Marine Industries, Inc.	Missouri
DMS Health Technologies, Inc.	North Dakota
DMS Imaging, Inc.	North Dakota
DMS Computed Imaging, Inc.	Texas
DMS Imaging Canada, Inc.*	Province of Ontario, Canada
DMS Leasing Corporation*	North Dakota
Midwest Construction Services, Inc.	Minnesota
Aerial Contractors, Inc.	North Dakota
Moorhead Electric, Inc.	Minnesota
Lynk3 Technologies, Inc	Minnesota
AC Equipment	Minnesota
Ventus Energy Systems, Inc.	Minnesota
DDCFS, Inc.	South Dakota
Foley Company	Missouri
Chassis Liner Corporation	Minnesota
Chassis Liner Credit Corporation*	Minnesota
Chart Automotive LLC*	Minnesota
E. W. Wylie Corporation	North Dakota
Midwest Information Systems, Inc.	Minnesota
Midwest Telephone Company	Minnesota
Osakis Telephone Company	Minnesota
The Peoples Telephone Co. of Bigfork	Minnesota
Data Video Systems, Inc.	Minnesota
MIS Investments, Inc.	Minnesota

*Inactive

(Back To Top)

Section 4: EX-23 (CONSENT OF DELOITTE & TOUCHE LLP)

EXHIBIT 23

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Nos. 333-90952 and 333-11145 on Form S-3 and 333-25261, 333-73041, 333-73075 on Form S-8 of Otter Tail Corporation of our report dated February 23, 2004 (which express an unqualified opinion and includes an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards ("SFAS") No. 143 Accounting for Asset Retirement Obligations, and SFAS No. 149, Amendment of Accounting Standards Board Statement No. 133 on Derivative Instruments and Hedging Activities, and change in the method of accounting for goodwill and other intangible assets as described in Note 1) appearing in the 2003 Annual Report to Shareholders of Otter Tail Corporation and incorporated by reference in this Annual Report on Form 10-K of Otter Tail Corporation for the year ended December 31, 2003

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
March 12, 2004

(Back To Top)

Section 5: EX-24.A (POWERS OF ATTORNEY)

Exhibit 24-A

POWER OF ATTORNEY

I, KEVIN G. MOUG, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Chief Financial Officer and Treasurer of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Kevin G. Moug

Kevin G. Moug

In Presence of:

/s/ Jackie Rogness

/s/ Sandy Greenlund

POWER OF ATTORNEY

I, JOHN C. MAC FARLANE, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Chairman of the Board of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ John C. MacFarlane

John C. MacFarlane

In Presence of:

/s/ Gary J. Spies

/s/ Kenneth L. Nelson

POWER OF ATTORNEY

I, KAREN M. BOHN, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Karen M. Bohn

Karen M. Bohn

In Presence of:

/s/ Nathan I. Partain

/s/ Gary J. Spies

POWER OF ATTORNEY

I, THOMAS M. BROWN, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Thomas M. Brown

Thomas M. Brown

In Presence of:

/s/ Karen M. Bohn

/s/ John D. Erickson

POWER OF ATTORNEY

I, DENNIS R. EMMEN, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Dennis R. Emmen

Dennis R. Emmen

In Presence of:

/s/ Arvid R. Liebe

/s/ Robert N. Spolum

POWER OF ATTORNEY

I, ARVID R. LIEBE, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Arvid R. Liebe

Arvid R. Liebe

In Presence of:

/s/ Dennis R. Emmen

/s/ Robert N. Spolum

POWER OF ATTORNEY

I, KENNETH L. NELSON, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Kenneth L. Nelson

Kenneth L. Nelson

In Presence of:

/s/ John C. MacFarlane

/s Gary J. Spies

POWER OF ATTORNEY

I, NATHAN I. PARTAIN, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Nathan I. Partain

Nathan I. Partain

In Presence of:

/s/ Kenneth L. Nelson

/s/ Gary J. Spies

POWER OF ATTORNEY

I, GARY J. SPIES, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Gary J. Spies

Gary J. Spies

In Presence of:

/s/ John C. MacFarlane

/s/ Kenneth L. Nelson

POWER OF ATTORNEY

I, ROBERT N. SPOLUM, do hereby constitute and appoint JOHN D. ERICKSON and GEORGE A. KOECK, or any one of them, my Attorney-in-Fact for the purpose of signing, in my name and on my behalf as Director of Otter Tail Corporation, the Annual Report of Otter Tail Corporation on Form 10-K for its fiscal year ended December 31, 2003, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Date: March 8, 2004

/s/ Robert N. Spolum

Robert N. Spolum

In Presence of:

/s/ Arvid R. Liebe

/s/ Dennis R. Emmen

(Back To Top)

Section 6: EX-31.1 (CERTIFICATION OF CHIEF EXECUTIVE OFFICER)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John D. Erickson, certify that:

1. I have reviewed this annual report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 12, 2004

/s/ John D. Erickson

John D. Erickson
President and Chief Executive Officer

(Back To Top)

Section 7: EX-31.2 (CERTIFICATION OF CHIEF FINANCIAL OFFICER)

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kevin G. Moug, certify that:

1. I have reviewed this annual report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 12, 2004

/s/ Kevin G. Moug

Kevin G. Moug
Chief Financial Officer and Treasurer

(Back To Top)

Section 8: EX-32.1 (CERTIFICATION OF CEO - SECTION 906)

Exhibit 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the "Company") on Form 10-K for the period ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John D. Erickson, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ John D. Erickson

John D. Erickson
President and Chief Executive Officer
March 12, 2004

(Back To Top)

Section 9: EX-32.2 (CERTIFICATION OF CFO - SECTION 906)

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the "Company") on Form 10-K for the period ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kevin G. Moug, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Kevin G. Moug

Kevin G. Moug
Chief Financial Officer and Treasurer
March 12, 2004

(Back To Top)